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OIL REPLACEMENT ANALYSIS PHASE II

EVALUATION OF SELECTED TECHNOLOGIES

November 1984

This is an OTA Working Paper that has been neither reviewed nor approved by the Technology Assessment Board.

J952-67

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OTA WORKING PAPER

This report is an OTA Working Paper, which was used in the preparation of OTA's final assessment report. OTA makes these working papers available for the use of readers desiring a more detailed or technical discussion of an issues than can normally be accomodated in our final report. An an OTA working paper, this report has not been reviewed or approved by the Technology Assessment Board. The findings and conclusions expressed in the report are those of the authors and do not necessarily reflect the views of OTA, the advisory panel, or the Technology Assessment Board.

Final Report

Oil Replacement Analysis Phase II—Evaluation of Selected Technologies

Submitted to

Office of Technology Assessment
United States Congress
Washington, D.C.

August, 1983

Gibbs & Hill, Inc.

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I. EXECUTIVE SUMMARY

The Office of Technology Assessment (OTA) of the U.S. Congress has initiated a study to evaluate the ability of various oil replacement technologies (ORT's), under a rapid deployment scenario, to mitigate the effects of a sudden cutoff of 3 to 4 million barrels per day (MMbbl/d) of oil imports. Gibbs & Hill (G&H) has completed Phase I of this study in which the most promising ORT's were selected for further evaluation. In the Phase II study, presented herein, G&H has evaluated the selected ORT's with regard to oil replacement potential and rate of replacement. The maximum replacement potential is 2.7 MMbbl/d within 5 years based on summing the potential of each technology after imposing independent constraint limitations. When these constraints are mutually applied, the oil replacement potential of the selected technologies is likely to be in the area of 1.6 MMbbl/d.

The following can be concluded:

- Two years after the oil disruption the only appreciable oil displacement that will have occurred is from residential, industrial and utility conversions to natural gas. These conversions provide oil displacement of approximately 600,000 barrels of oil equivalent per day (boe/d) at the end of 2 years.

- Within the five-year period the bulk of the oil replacement occurs with oil and gas industry technologies, i.e., enhanced oil recovery (EOR) and increased natural gas production, transportation and conversions. The capital investment required is $50 to 100 billion for the oil and gas industry alone which is an imposing constraint.

- Most of the technologies require long lead times for design, procurement and construction, with competition among the technologies for similar hardware components, architect-engineering-construction management (AE&C) services, skilled labor, environmental permitting and capital. Proper prioritizing of hardware availability, resource use and environmental issues can minimize the impact of these mutual constraints.

- Availability of solid fuel-fired boilers (field erected), particulate control systems and ash disposal sites will constrain the deployment of coal-water mixture (CWM), coal and wood use in the industrial sector, EOR projects and manufacture of ethanol.

- Should environmental restrictions in California preclude thermal EOR and CWM boiler conversion projects the oil displacement decreases by only 55,000 boe/d. This occurs because the delay of these projects provides critical hardware that might otherwise have not been available to other technologies.

In preparing for the occurrence of a major oil disruption the following should be considered to accelerate oil displacement:

- Regulatory policy should continue to promote the exploration and production of unconventional natural gas sources.

- There is sufficient major pipeline capacity in the Northeast and West to transport the anticipated increase in natural gas production (See Appendix D). It was concluded that the smaller distribution systems may initially constrain deployment of gas conversions but that within the five-year time frame sufficient enlargement of systems could be accomplished. An in-depth regional study of these smaller distribution systems is required to identify where possible pipeline and storage constraints to early deployment of natural gas conversion might exist. These secondary pipeline systems could be enlarged as part of a national security effort similar to the strategic petroleum reserve program.

- CWM conversions are offered commercially by several suppliers but there has not been widespread commercial acceptance. Because of its unique advantages in terms of ease of fuel switching and cost, efforts to further advance CWM technology and commercialization should be encouraged by the federal government. For emerging technologies such as CWM this may best be accomplished by providing tax incentives to companies advancing the technology and to those burning CWM fuel.

- Legislation that permits delayed compliance with environmental regulations in the event of an oil disruption crisis should be considered. Historically this has been permitted on a limited basis by the E.P.A. in order to promote coal conversion. Applied on a national basis this could accelerate technology deployment where hardware availability is a problem.

II. INTRODUCTION

The Office of Technology Assessment (OTA) has initiated a study to analyze the effects of a sudden and protracted disruption of a 3 to 4 MMbbl/d imported oil supply. Gibbs & Hill, Inc. (G&H) has been authorized by OTA to study the rapid deployment of oil replacement technologies (ORT's) and their ability to mitigate the effects of the disruption. In Phase I of this study G&H, in consultation with OTA, selected the following ORT's for more detailed Phase II evaluation:

A. Coal-Water Mixtures (CWM)

B. Wood and Coal Combustion in Industry

C. Enhanced Oil Recovery

D. Natural Gas Production, Storage and Transportation

E. Compressed Natural Gas/Liquefied Petroleum Gas Powered Vehicles

F. Ethanol from Corn

These ORT's are evaluated in Appendices A through F in accordance with the following work plan:

A. <u>COAL-WATER MIXTURES (CWM)</u>

1. Identify geographic region for deployment.

2. Estimate the number of boiler plants for the utility and industrial sectors in each region.

3. Establish average preparation and boiler plant sizes for both on-site and off-site CWM preparation in each sector.

4. Size critical components requiring long lead times, in both CWM preparation plants and boiler modifications.

5. Provide a schedule for rapid deployment of CWM technology (on-site and off-site preparation plants) with estimates of each critical path segment.

6. Compare peak yearly requirement of critical components to historic U.S. production capacity. Peak yearly requirement will be based on starting all projects of the same time, i.e., overnight start after the oil cutoff. If equipment availability does not satisfy the

accelerated demand under overnight start, the start of projects would then be staggered to explore whether equipment availability constraints could be overcome.

7. Determine the extent to which bottlenecks created by skilled manpower shortages occur as a result of overnight start of all projects. If yes, the start of projects would then be staggered.

8. Determine the deployment rate of CWM fuel substitution for each region.

9. Review the $/boe costs from Phase I to determine if any major refinements are required as a result of the Phase II analysis.

10. Identify any technological and environmental "unknowns" that might restrict deployment of CWM fuels. Identify programs to be undertaken to address these "unknowns".

B. WOOD AND COAL COMBUSTION IN INDUSTRY

1. Identify geographic regions attractive for switching to wood and coal fuels (direct-firing or as low-Btu gas).

2. Estimate the number of boiler plants in the industrial sector to be repowered by wood and coal in each region.

3. Establish an average plant size for each fuel.

4. Size critical components requiring long lead times for each fuel.

5. Provide a schedule for rapid deployment of each fuel technology with estimates of each critical path segment.

6. Compare peak yearly requirement of critical components to historic U.S. production capacity. Determine this for overnight start and, if sufficient deployment cannot be accomplished, utilize staggered start of projects.

7. Determine the extent to which bottlenecks created by skilled manpower shortages occur as a result of overnight start of all projects. If yes, the start of projects would then be staggered.

8. Determine the deployment rate of each fuel technology for each geographic region.

9. Review the $/boe costs from Phase I to determine if any major refinements are required as a result of the Phase II analysis.

10. Identify any technological and environmental "unknowns" that might restrict switching to wood and coal fuels. Identify programs to be undertaken to address these "unknowns."

C. ENHANCED OIL RECOVERY

1. Identify geographic regions for deployment.

2. Estimate the number of steam and CO_2 injection projects in each region.

3. Establish the average steam and CO_2 injection project size.

4. Size critical components requiring long lead times for both type of projects.

5. Provide a schedule for rapid deployment of a steam and a CO_2 injection project.

6. Compare peak yearly requirement of critical components (e.g. drilling rigs) to availability and to historic U.S. production capacity. Determine these areas for overnight start and, if sufficient deployment cannot be accomplished, utilize staggered start of projects.

7. Determine the extent to which bottlenecks created by skilled manpower shortages occur as a result of overnight start of all projects. If yes, the start of projects would then be staggered.

8. Determine the deployment rate of each type of project for each region.

9. Review the $/boe costs from Phase I to determine if any major refinements are required as a result of the Phase II analysis.

10. Identify any technological and environmental "unknowns" that might restrict EOR projects including transportation of oil to refineries that can process the recovered oil. Identify programs to be undertaken to address these "unknowns."

D. NATURAL GAS PRODUCTION, TRANSPORTATION AND STORAGE

1. Identify, regionally, the areas of natural gas production, transportation routes to end-users and storage areas.

2. Estimate the number of drilling sites, additional pipelines and storage caverns.

3. Describe critical components related to natural gas production, transportation and storage.

4. Provide a schedule for rapid deployment of natural gas production, transporation and storage.

5. Compare peak yearly requirement of critical components to availability (such as drilling rigs) and to historic U.S. production capacity. Determine these areas for overnight start and, if sufficient deployment cannot be accomplished, utilize staggered start of projects.

6. Determine the extent to which bottlenecks created by skilled manpower shortages occur as a result of overnight start of all projects. If yes, the start of projects would then be staggered.

7. Determine the deployment rate for additional natural gas production, transporation and storage.

8. Review the $/boe costs from Phase I to determine if any major refinements are required as a result of the Phase II analysis.

9. Identify any technological and environmental "unknowns" that might restrict deployment of additional natural gas production, transportation and storage. Identify programs to be undertaken to address these "unknowns."

E. CNG/LPG POWERED VEHICLES

1. Determine critical components required for converting vehicles to CNG/LPG powering.

2. Compare peak yearly requirement of critical components to historic U.S. production capacity.

3. Determine the deployment rate for CNG/LPG powered vehicles.

F. ETHANOL FROM CORN

1. Provide a schedule for rapid deployment of ethanol plants, including both the field erected type and prefabricated ones.

2. Identify critical components for both types of plants.

3. Compare peak yearly requirement of critical components to historic U.S. production capacity.

4. Determine deployment rate of ethanol plants.

Based on the data presented in Appendices A through F, the mutual constraints to deployment of the ORT's are examined in Section III. As a result of these mutual constraints the aggregate deployment rate of ORT's is evaluated in Section IV.

III. EVALUATION OF CONSTRAINTS

A. INTRODUCTION

The constraints to deployment of the energy supply technologies are evaluated individually in Appendices A through F of this report. For example, CWM (Appendix A) and solid fuel industrial conversions (Appendix B) are based on conversion of the same industrial boiler population. The deployment rates by Federal Region for each technology are based on regional considerations; schedular lead times; equipment, manpower and resource availabilities; and environmental regulations. The breakdown of Federal Regions is shown in Figure III-1. In this section the mutual constraints (either potential or actual) among the technologies are examined to permit appropriate further adjustments to the deployment rates of each technology.

B. MUTUAL CONSTRAINTS

The mutual constraints to deployment of technologies in Appendices A through F can be categorized as follows:

1. Hardware
2. Resources
3. Capital
4. Manpower.

1. Hardware

The mutual hardware and resource constraints are shown in Table III-1. The annual requirements for hardware and resources for each ORT are shown in Table III-2. Hardware constraints exist for solid fuel-fired boilers (field erected) and for particulate control systems (PCS's). Since these components are required in tandem, the component imposing the most constraint will dictate the level of technology deployment. In this case, the availability of PCS's presents the greatest shortfall and will dictate the ability to deploy the technologies of CWM-, coal- and wood-fired boilers, enhanced oil recovery (EOR) and manufacture of ethanol.

The availability of 760 drilling rigs for the exploration and production for natural gas and EOR appears to be adequate based on the 2700 idle rigs in 1983. However, this conclusion must be viewed with caution, since after the oil crisis, the level of conventional oil drilling will increase

dramatically and rig availability could delay the progress of both EOR and natural gas (not associated with oil) projects.

Based on historical availability, neither large gas compressors nor solid fuel handling facilities limit the deployment of any technology.

2. Resources

As shown in Table III-2 of the potential resource constraints, the projected coal requirement of 113.2 million tons per year is 17 percent of the 656.9 million tons per year historically available [6]. Furthermore, the 113.2 million tons represents less than a 12 percent increase per year over three years in annual low sulfur coal production. This increase in coal consumption is small enough to be accommodated by both the mining and transportation sectors. Detailed discussions of these sectors and their capacities are presented in Appendix A of this report and Section IV of the Phase I Report, respectively.

The increases in required ash disposal in Federal Regions 1, 2 and 9 is large and will undoubtedly be a difficult environmental hurdle to overcome. Disposal of ash is regulated by many laws, the most vigorous of which are the Resource Conservation and Recovery Act (RCRA), the Clean Water Act (CWA) and Safe Drinking Water Act (SDWA).[1,2] Producers of waste must determine if waste is hazardous (ignitible, corrosive, reactive or toxic) and, if so, the regulations for transporting, treating, storing, etc., imposed by RCRA are very strict. Leachates from the disposal site and nearby groundwater may require monitoring as set forth in CWA and SDWA. The large increases in ash disposal in Regions 1, 2 and 9 may tax the available disposal sites and could delay the start of projects because of permitting delays.

3. Capital

The capital required to deploy all of the Phase II technologies totals $64 to 127 billion as shown in Table III-3. Based on rates of deployment presented in Appendices A through F, most of this expenditure is concentrated in the first two to three years following the oil disruption. Added to this capital outlay is the money required for deployment of other technologies considered in the Phase I analysis. These technologies provide options for oil displacement in the residential/commercial sector through the use of electric heaters, heat pumps, coal, wood and solar energy. These technologies will certainly be deployed after

the oil crisis, albeit, at a lower oil displacement rate than that for those selected for Phase II analysis. Excluding solar energy, these technologies could replace 200,000 boe/d at a cost of $7 billion. If the full potential of solar energy in the residential/commercial sector in 1990 is reached (see Phase I Report) another 75,000 boe/d at a cost of $15 billion can be displaced. As discussed in the Phase I Report by 1995 the full potential of 128,000 boe/d could be reached with slightly lower unit costs (constant dollars). These residential/commercial expenditures are more dispersed through the 5-year period after the crisis than the bulk of the Phase II technology capital requirements.

The availability of $80 to 150 billion for deployment of the technologies is potentially a formidable constraint. As much as one-half of this amount must be expended by the oil and gas industry over 2 to 3 years, which brings the required yearly investment to the $20 to 40 billion range. This may present a constraint to the oil and gas industry in which the 1982 total capital spending of approximately $75 billion was close to the historical high of approximately $82 billion in 1981.[4,5] Industries may also experience difficulty in raising the levels of capital required for fuel conversions and ethanol plants.

The above analysis is based on a summation of the expected costs for individual projects. Simultaneous, increasing levels of demand result in a strain on existing supply, capabilities and infrastructure to carry forth projects and has resulted in the past in price increases above the general inflation rate.[6] These additional costs have been termed "factor cost inflation" and will exacerbate capital availability problems.

4. Manpower

Constraints in manpower may result if all technologies are deployed to the extent shown in Table III-3. All of the technologies, excluding natural gas conversions and gaseous fuel vehicles, require construction-type projects, which total $51 to $104 billion. About 40 percent of construction costs are estimated to be services, the balance being materials and equipment. The services include technical services for project definition and plant design, management services, supervisory services, skilled labor and general labor. Architect/engineering and construction management (AE&C) services are estimated at 10 percent of the total investment (25 percent of the total services).

On this basis $5 to 10 billion of AE&C services and $15 to 32 billion of other construction labor are required. For

analysis, a 2-year expenditure period is assumed. Using $100,000/man-year for AE&C services and $50,000/man-year for other labor the manpower required per year is 25,000 to 50,000 AE&C type and 150,000 to 320,000 other labor. Some standardization of design and procurement may help relax somewhat the AE&C constraint but nevertheless at some point it will likely become a binding constraint, i.e., one that impedes the technology deployment rate. Total AE&C manpower is estimated at 125,000 based on 85,000 personnel in the fifteen largest firms [7,8] and the balance from the hundreds of smaller firms and from those working for oil companies. The AE&C industry can respond by extending work hours and hiring additional staff but it is reasonable to expect that the 25,000 to 50,000 personnel required in addition to ongoing project activities will impede technology deployment. The 150,000 to 320,000 other labor includes skilled construction labor which may be a more short-term constraint than the AE&C one, but one that will also exist in early stages of the crisis period based on the total of 922,000 heavy construction employees.[9]

TABLE III-1

MUTUAL HARDWARE AND RESOURCE CONSTRAINTS OF OIL REPLACEMENT TECHNOLOGIES

Mutual Constraint (Potential or Actual)	Oil Replacement Technologies
Packaged Boilers	• Industrial Conversions to CWM • CO_2 EOR • Steam EOR
Field Erected Boilers	• Industrial Conversions to Coal and Wood • Ethanol Manufacture
Particulate Control Systems	• Industrial Conversions to CWM, Coal and Wood • CO_2 EOR • Steam EOR
Coal	• Utility Conversions to CWM • Industrial Conversions to CMW and Coal • CO_2 EOR • Steam EOR
Solid Fuel Handling Facilities (< 50 tph)	• Industrial Conversions to CWM, Coal and Wood • CO_2 EOR • Steam EOR • Ethanol Manufacture
Ash Disposal	• Utility Conversions to CWM • Industrial Conversions to CMW and Coal • Steam EOR
Gas Compressors (> 350 hp)	• CO_2 EOR • Natural Gas
Drilling Rigs	• CO_2 EOR • Steam EOR • Natural Gas

TABLE III-2
ANNUAL HARDWARE AND RESOURCE REQUIREMENTS OF
OIL REPLACEMENT TECHNOLOGIES

MUTUAL CONSTRAINTS (YEARLY BASIS) Compete for same market / TECHNOLOGIES		SOLID FUEL BOILERS (UNITS) <100×10⁶ Btu/hr (PACKAGED)	SOLID FUEL BOILERS (UNITS) >100 × 10⁶ Btu/hr (FIELD ERECT)	PCS's (UNITS) INDUSTRIAL BOILER SIZED	COAL (10^3 TONS) LOW SULFUR	SOLID FUEL HANDLING FACILITIES (UNITS) <50tph	ASH DISPOSAL (10^6 Tons) Regions 1	2	4	9	GAS COMPRESSORS (UNITS) >350hp	DRILLING RIGS (UNITS)
A. CWM	Utility	----	----	----	47.4	----	0.67	0.95	0.78	0.92	----	----
	Industrial	303	----	328**	16.4	328	0.16	0.28	0.26	0.03	----	----
B. Direct Firing (Industrial)	Coal	----	157								----	----
	Wood	----			----						----	----
C. Enhanced Oil Recovery	CO_2	50	----	50	4.1	50	----	----	----	----	135	300
	Steam	320	----	320	15.8	320	----	----	----	1.11	----	160
D. Natural Gas	Utility	----	----	----	----	----	----	----	----	----		
	Industrial	----	----	----	----	----	----	----	----	----	2100***	300***
	Res/Comm	----	----	----	----	----	----	----	----	----		
E. Gaseous Fueled Vehicles	CNG	----	----	----	----	----	----	----	----	----	----	----
	LPG	----	----	----	----	----	----	----	----	----	----	----
F. Ethanol		----	100	100	29.6	100	----	----	----	----	----	----
Projected Required		673	257	798	113.2	798	0.83	1.23	1.04	2.06	2235	760
Projected Available		800	157	330	----	>1000	----	----	----	----	----	----
Historically Available		----	----	----	656.9	----	0.11	1.13	10.1	1.29	5512	2700*

* Number of idle rigs in 1983
** Includes amount required for gasifiers
*** Total compressors and rigs required for all sectors.
Note: See Appendices A through F for details.

TABLE III-3

CAPITAL COSTS AND DEPLOYMENT LEVEL OF OIL REPLACEMENT TECHNOLOGIES

	Technology	Oil Displaced/ Produced (bbl/d)(a)	Capital Cost ($/boe/d)(b)	Capital Cost (10^9)
A.	CWM			
	Utility	431,650	11,800-15,800	5.1-6.8
	Industrial*	187,500	13,800-20,800	2.6-3.9
B.	Direct Firing (Industrial)	203,000		2.6-10.6
	Coal*	203,000	37,000-52,000	7.5-10.6
	Wood*	166,000	32,000-38,000	5.3-6.3
C.	Enhanced Oil Recovery			
	Steam	500,000	10,500-19,900	5.3-10.0
	CO_2	275,000	20,000-41,000	5.5-11.3
D.	Natural Gas			
	Supply	(c)	60,000-120,000	30.0-60.0 (c)
	Conversion			
	Residential/Commerical	441,550	16,000-25,000	7.1-11.0
	Industrial	455,650	8,000-12,500(d)	3.6-5.7
	Utility	102,800	----	(e)
E.	Gaseous Fueled Vehicles			
	CNG	37,000-87,000	33,000-51,000	1.2-4.4
	LPG	35,000	21,000-52,000	0.7-1.8
F.	Ethanol	200,000	20,000-35,000	40.0-70.0
	Total	2,681,650 - 2,731,650		$65.1-128.6

*Compete for same market

Notes:

(a) See Appendices A through F for details

(b) Constant mid-1982 dollars from Phase I Report

(c) Total of 2 tcf/y (1,000,000 boe/d). Capital cost based on developing 1 tcf/y (500,000 boe/d) of new natural gas supplies at $/boe/d indicated. Balance 1 tcf/y is obtained from spare capacity in Lower 48 and accelerated deliverability from existing fields (See Appendix D).

(d) Based on economies of scale, $/boe/d is assumed at 50 percent of resident/commercial cost.

(e) Most utility switching to natural gas is performed at no cost. Some utilities require pipelines but these total less than $50 million and are negligible in this analysis. Pipeline cost derived from Reference (3).

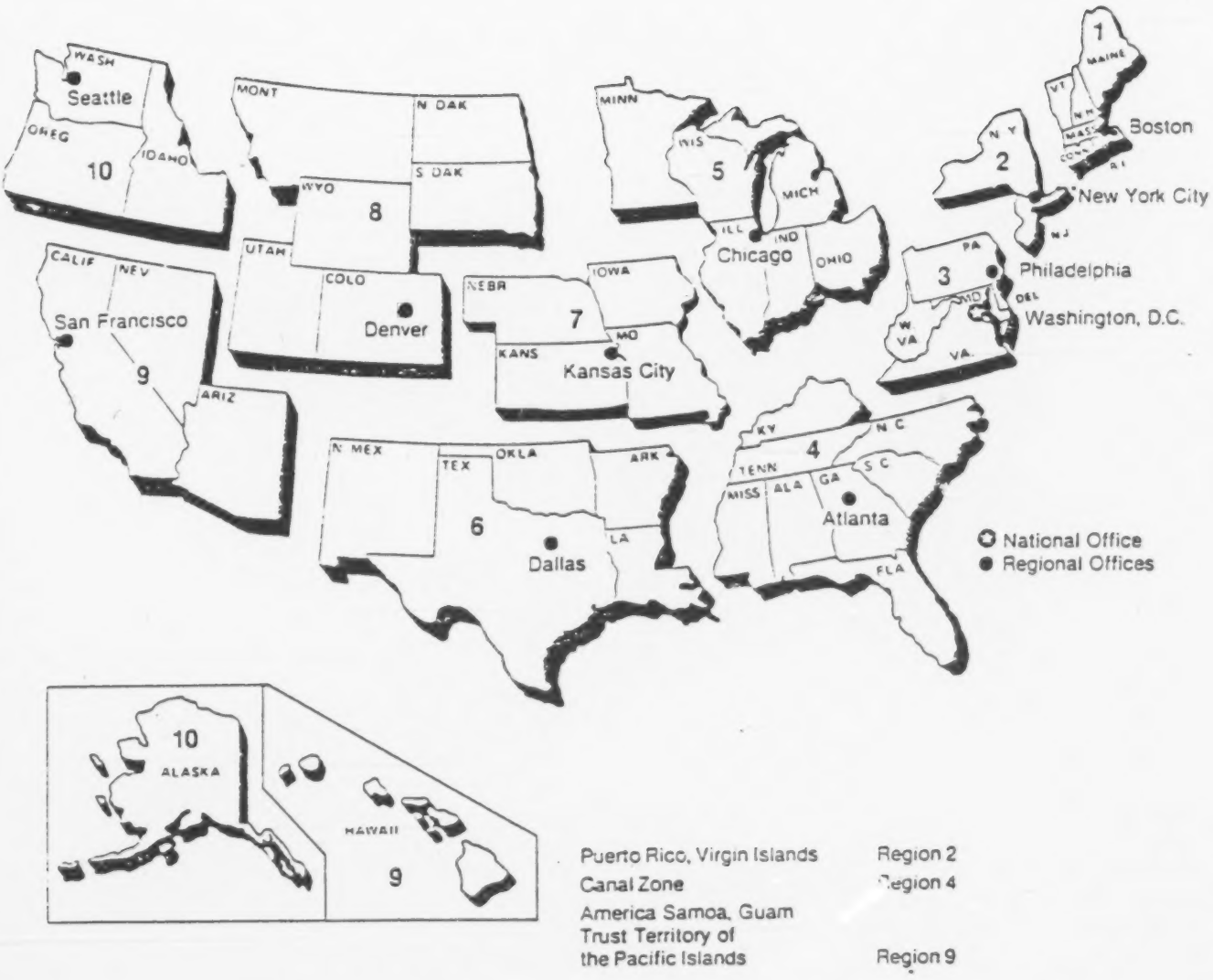

FIGURE III-1

FEDERAL REGIONS

IV. AGGREGATE DEPLOYMENT RATE

The deployment rates of the energy supply technologies are presented in Appendices A through F. The total potential oil displacement/production at the end of the five-year period is approximately 2.7 million boe/d as shown in Table III-3. This figure does not reflect the mutual constraints among the technologies presented in Section III. It is apparent that mutual constraints exist that will prevent the full realization of the 2.7 million boe/d potential.

The most binding constraint is that of particulate control systems (PCS's). A delay of one-year in procuring PCS's for EOR would effectively preclude any EOR in the five-year period. A similar delay of PCS's for industrial CWM, coal and wood conversions and ethanol plants would reduce their oil displacement by 25 percent in the five-year period. In addition, an EOR project on a steam Btu basis produces three times the oil that a conversion project displaces. In terms of national benefits it would appear that EOR projects should be assigned priority in procurement of PCS's in the event of an oil disruption. However, thermal EOR projects are very demanding in terms of using critical hardware and resources (See Table III-1). The assignment of critical components as it effects oil displacement is examined further in this section.

Regional coal ash disposal may require controversial policy decisions to be made that compromise environmental impact and national economy and social benefits. Delays in implementation of EOR projects and industrial fuel conversions based on environmental permitting problems would result in similar oil replacement reductions as with limited PCS availability. It is quite possible that because of these environmental related problems that oil companies will forego solid fuel-firing and use either oil or gas as fuel. In the first case the thermal EOR oil replacement would be reduced by one-third as discussed in the Phase I report; the CO_2 EOR oil replacement utilizing CO_2 derived from power plant flue gas would be reduced by over one-third. Furthermore if gas-firing were employed, this would limit the additional natural gas available for residential, commercial and utility conversions.

The other potentially constraining environmental issue is that of SO_2 and NOx emissions. It has been assumed in our analysis that in the crisis situation Federal regulations will be followed and that additional state and local restrictions may have to be relaxed. Technologies exist that can satisfy the sometimes more rigorous state and local regulations and these alternatives may be used at higher cost and with potential delays in the hope of providing a delicate balance between energy projects and environmental protection. It should be recognized that any compromise of environmental protection, no matter how cost-benefit effective can be highly controversial.

The atmospheric emissions regulations in California are a particularly thorny area that may severely limit the potential, additional 500,000 bbl/d oil production from thermal EOR. The effect of this eventuality on total oil displacement is evaluated further in this Section. As discussed in Appendix A, most other areas of the country are attainment areas with regard to acceptable regulatory levels of SO_2 and NOx. Conversion or substitution of boilers, particularly older industrial ones from oil to coal-firing, would not necessarily raise the NOx level since many of the older units were designed without NOx emission control. The new coal-fired installations would have to meet the newer, more stringent NOx regulations which can be attained with existing combustion technology. Similarly, SO_2 requirements for the coal based technologies have been met through the use of low sulfur coal. Should flue gas desulfurization systems be required for utility and large industrial installations, the deployment of the coal based technology would be delayed 6 to 12 months from the levels indicated in the Appendices. For example, the rate of oil displacement for utility CWM conversions would begin at approximately the 3-year area instead of at 2 years 3 months. At the 5-year timeframe, however, the daily oil displacement would remain unchanged for this technology.

The attainment status of each area of the country with regard to particulate, SO_2 and NOx will have to be evaluated in the permitting stage and will certainly affect the investment and time required for fuel conversion.

To summarize, it appears that there are mutual constraints among the energy supply technologies that are binding and will limit oil replacement/production in response to an oil disruption. It is difficult to quantify the effects of these constraints because the controlling issues are speculative at best:

- What priorities will be assigned to equipment procurement?
- How long will the environmental permitting task be delayed as a result of ash disposal issues, NOx regulations, etc.?
- Will conventional oil well drilling severely limit the rigs available for EOR and non-associated gas wells?
- Can standardization of plant designs or accelerated manpower training relieve the anticipated early shortage of AE&C and skilled labor personnel?
- How quickly can the economy respond to a demand for $90 to 160 billion?

The answers to these questions involve policy issues that will demand government review and oversight with the recognition of the

importance of private decision-making in fostering an efficient and hopefully permanent solution to the oil crisis. The nation will continue to have environmental as well as energy supply goals and this dichotomy makes policy decisions difficult to predict. One can safely assume that the 2.7 million boe/d replacement potential cannot be reached because of the mutual constraints that exist. Two oil displacement scenarios that include assumptions addressing some of the above questions are evaluated below.

Tables IV-1 and IV-2 present the effects of mutually applying the hardware and ash disposal constraints of Table III-1 on the oil displacement of 2.7 MMbbl/d. The constraints are applied to the various technologies such that the reduction in oil displacement is minimized, i.e., the technology that most efficiently utilizes a constraining component in terms of oil displacement is assigned priority in obtaining that component. The following describes the derivation of Table IV-1:

- Large Boilers - Since ethanol plants have the highest oil displacement per boiler (See Tables III-1 and III-2), these plants are assigned the full number of boilers required (100). The balance available (57) are able to supply 36.3 percent (=57/157) of large industrials switching to direct firing of coal. Under this scenario, the balance of the industrials (63.7 percent) which cannot obtain large boilers for coal-firing convert to CWM which displaces 119,427 boe/d (= 0.637 x 187,500). This mix of technology deployment, based on the large boiler constraint, results in an oil displacement reduction of approximately 10,000 boe/d.

- Particulate Control Systems - Priority for PCS's are assigned to ethanol plants and CO_2 EOR projects due to their high oil displacement per installation. Thermal EOR is assigned the remaining 180 units (=330-100-50) reducing thermal EOR oil displacement by 44.7 percent (=180/320). The industrial boiler conversions to either CWM, coal, wood or coal gas firing have the lowest oil displacement per PCS and their allocation of PCS's and oil displacement is zero. Based on the mutual PCS constraints, oil displacement decreases by approximately 412,000 boe/d.

- Ash Disposal - The largest increase in one year in ash disposal requirements in recent history has been 9 percent.[6] Assuming a doubling of this capability in a crisis, ash disposal increases over two years of 0.04, 0.45, 4.1 and 0.52 x 10^6 tpy in Regions 1, 2, 4 and 9, respectively, are realized. Since industrial conversions in our scenario are reduced to zero based on the PCS constraint, all of the ash disposal increase is available to utility CWM conversions in Regions 1, 2 and 4. The oil displacement in Region 1 is reduced to 6 percent (=0.04/0.67) of its potential or 6,240 boe/d, and Region 2 to 47 percent or 70,641 boe/d. Region 4 has adequate ash disposal capability to

realize all of the 81,000 boe/d potential. Using a maximum oil displacement methodology, all of the available ash disposal capability is assigned to thermal EOR in Region 9 eliminating utility CWM in Region 9. Thus, the total utility CWM for the nation is 157,881 boe/d. Based on PCS availability, ash disposal requirements for thermal EOR is reduced to 0.62 tpy from 1.11 tpy. Thus, 83.9 percent (=.52/0.62) or 235,510 boe/d of the thermal EOR potential can be realized. Mutually applying the ash disposal constraint reduces the oil displacement by approximately 319,000 boe/d. Obviously, the impact of ash disposal would have been greater had the boiler and PCS availabilities not reduced ash disposal requirements.

- Drilling Rigs - In the event of the oil disruption crisis and a sharp oil price increase, drilling rigs will be in great demand for conventional oil exploration. Drilling rig efficiency in terms of oil displacement is highest for thermal EOR, lowest for CO_2 EOR. If only half of the required number of drilling rigs are available for the oil replacement technologies, these 380 should be assigned first to thermal EOR (75) and natural gas production (300) leaving a limited number of rigs (5) for CO_2 EOR. The constraint of drilling rig availability reduces oil displacement by approximately 271,000 boe/d.

Assignment of critical hardware and resources in the above scenario results in a total reduction in oil displacement of approximately 1,000,000 boe/d. Another scenario is presented in Table IV-2.

As shown in Table III-1 steam EOR is very demanding in terms of its use of critical hardware and resources. Without thermal EOR, mutual constraints are expected to be less restrictive. Should the NOx emission issue in California delay environmental permit approval for thermal EOR from the suggested 10 month span to 2-years or longer (See Figure C-1), there would be no oil production increase from thermal EOR in the 5-year period as shown in Column 3 of Table IV-2. Procurement of critical PCS hardware would no longer compete in the same time period with other technologies. Thus, the 180 PCS's assigned to thermal EOR can be utilized for CWM, coal, wood or coal gas firing of industrial boilers. Assuming 57 PCS's for direction firing and the balance for CWM firing yields an oil displacement of approximately 144,000 boe/d [=73,700 + (123/320)(187,500)]. This industrial oil displacement must next be evaluated on the basis of ash disposal capability by Region. For maximum displacement the boiler conversions would take place in those Regions without ash disposal limitations, i.e., Regions 3 to 8 and 10 which total 126,250 boe/d oil displacement (See Tables A-8 and B-1). It is assumed that the balance of 17,750 boe/d cannot be realized because the ash disposal capability in Regions 1, 2 and 9 is exhausted by the requirements imposed by utility CWM-firing.

Without thermal EOR in Region 9 utility CWM-firing can utilize the postulated additional 0.52 x 10^6 tpy ash disposal capability. This provides enough disposal capability for 56.5 percent (0.52/0.92) or 54,826 boe/d oil displacement by utility CWM in Region 9 bringing total utility CWM to 212,707 boe/d. Also, with a delay in initiation of thermal EOR project construction, additional drilling rigs can be available for CO_2 EOR projects resulting in oil production of 73,333 boe/d [=(80/300)(275,000)].

Thus, as shown in Table IV-2 the delay of thermal EOR projects results in a slightly lower decrease in oil displacement due to mutual constraints. The resulting oil displacement is approximately 14,000 boe/d more than the scenario presented in Table IV-1. However, if the environmental issues in Region 9 prevent incorporation of industrial and utility CWM conversions as well as thermal EOR, the oil displacement is approximately 55,000 boe/d less as shown in the final column of Table IV-2.

Natural gas conversions and CNG and LPG vehicles do not have mutual constraints with the other oil replacement technologies and provide a total of approximately 1.13 MMboe/d oil displacement. As shown in Tables IV-1 and IV-2, after applying mutual constraints, the other technologies may add another 0.5 to 0.6 MMboe/d.

There are, of course, other scenarios that may be constructed that would shift the oil displacement from one technology to another. For example, thermal EOR projects could be based on gas turbine cogeneration with natural gas firing depending on the location and size of gas pipelines. Gas turbines with water or steam injection for NOx control would ameliorate the environmental restrictions. This would decrease the natural gas available to the industrial and residential/commercial sectors (Appendix D), but electricity provided by cogeneration could provide a substitute. Alternately, coal-fired steam turbine cogeneration facilities in lieu of steam-only facilities could be utilized for thermal EOR. The electrical output could economically justify the use of catalytic reduction for NOx control to ameliorate environmental restrictions. Both of the above alternates were not considered in detail by Gibbs & Hill since they are based on cogeneration, a technology which was outside the intended scope of work. Nevertheless, these technologies would be given strong consideration in the event of the oil disruption crisis and would contribute favorably to lessening the reduction in oil displacement due to mutual constraints.

TABLE IV-1

EFFECT OF HARDWARE AND RESOURCE CONSTRAINTS
ON OIL DISPLACEMENT

Technology	Mutual Constraint	Oil Displacement (boe/day) None	Large Boilers	PCS's	Ash Disposal	Drilling Rigs
A. CWM	Utility	431,650	431,650	431,650	157,881	157,881
	Industrial	(1)	119,427	0	0	0
B. Direct Firing (Industrial)	Coal	203,000(1)	73,700	0	0	0
	Wood	(1)	(1)	0	0	0
C. EOR	CO_2	275,000	275,000	275,000	275,000	4,580
	Steam	500,000	500,000	280,800	235,510	235,510
D. Natural Gas	Res/Comm	441,550	441,550	441,550	441,550	441,550
	Industrial	455,650	455,650	455,650	455,650	455,650
	Utility	102,800	102,800	102,800	102,800	102,800
E. Gaseous Fueled Vehicles	CNG	62,000	62,000	62,000	62,000	62,000
	LNG	35,000	35,000	35,000	35,000	35,000
F. Ethanol		200,000	200,000	200,000	200,000	200,000
TOTALS		2,706,650	2,696,777	2,284,450	1,965,391	1,694,971

(1) 203,000 boe/d is the largest oil displacement among the three technologies that compete for the large industrial boiler sector. CWM would replace 187,500 boe/d, direct wood firing 166,000 boe/d without applying mutual constraints. The actual oil displacement would consist of a mix among the three technologies.

TABLE IV-2

EFFECT OF HARDWARE, RESOURCE AND ENVIRONMENTAL PERMITTING CONSTRAINTS ON OIL DISPLACEMENT

Technology	Mutual Constraint	Oil Displacement (boe/day) None	Large Boilers	Region 9 Permitting Steam EOR	PCS's	Ash Disposal	Drilling Rigs	Region 9 Permitting CWM
A. CWM	Utility	431,650	431,650	431,650	431,650	212,707	212,707	157,881
	Industrial	(1)	119,427	119,427	70,300	52,550	52,550	52,550
B. Direct Firing (Industrial)	Coal	203,000(1)	73,700	73,700	73,700	73,700	73,700	73,700
	Wood	(1)	(1)	(1)	(1)	(1)	(1)	(1)
C. EOR	CO_2	275,000	275,000	275,000	275,000	275,000	73,333	73,333
	Steam	500,000	500,000	0	0	0	0	0
D. Natural Gas	Res/Comm	441,550	441,550	441,550	441,550	441,550	441,550	441,550
	Industrial	455,650	455,650	455,650	455,650	455,650	455,650	455,650
	Utility	102,800	102,800	102,800	102,800	102,800	102,800	102,800
E. Gaseous Fueled Vehicles	CNG	62,000	62,000	62,000	62,000	62,000	62,000	62,000
	LPG	35,000	35,000	35,000	35,000	35,000	35,000	35,000
F. Ethanol		200,000	200,000	200,000	200,000	200,000	200,000	200,000
TOTALS		2,706,650	2,696,777	2,196,777	2,147,650	1,910,957	1,709,290	1,654,464

(1) 203,000 boe/d is the largest oil displacement among the three technologies that compete for the large industrial boiler sector. CWM would replace 187,500 boe/d, direct wood firing 166,000 boe/d without applying mutual constraints. The actual oil displacement would consist of a mix among the three technologies.

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A. COAL-WATER MIXTURES

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1. INTRODUCTION

The Gibbs & Hill (G&H) Phase I report identified coal-water mixture (CWM) as an alternate fuel for replacing fuel oil in utility and industrial boilers. The preliminary oil replacement potential by the CWM technology was estimated to be as follows:

Utility Sector : 460,000 boe/d

Industrial Sector: 240,000 boe/d

In this Appendix, we have quantified, regionally, potential boiler conversions to burn CWM in both the utility and industrial sectors. It has been assumed that individual CWM preparation plants will be constructed to serve each utility boiler identified as a candidate for conversion to CWM-firing. This assumption presents a worst case scenario with respect to determining constraints associated with the deployment of the CWM technology in the utility sector. It is expected that, in reality, some CWM preparation plants will be built to serve several utilities in cases where land availability, economics, and logistics would dictate centrally located plants. Constraints for technology deployment have been identified and assessed to estimate a potential technology deployment rate during the 1985-1990 period.

2. PROJECTED OIL USE PROFILE

a. Utility Sector

Based on OTA projections for 1985,[1] four areas in the U.S. are expected to consume nearly 90 percent of all residual oil burned in the utility sector. These areas, standard Federal Regions 1, 2, 4, and 9 (see Table A-1), have been selected as the most likely regions where boilers will be converted to burn CWM. Also shown in Table A-1, are estimates of total electric output and capacity factors which are derived from OTA oil use projections.

The more than 1400 oil-fired boilers in Regions 1, 2, 4, and 9[2] (see Table A-1) account for all units, regardless of age, size, or capability to burn other fuels. However, for the purposes of this study, only those boilers that have capacities larger than 50 MWe and were operational no earlier than 1960 will be considered for conversion to CWM-firing. It is assumed that conversion of boilers older than 25 years (in 1985)

could not be justified considering life cycle conversion costs[3], and that small units (less than 50 MWe capacity) would suffer from diseconomies of scale. This is not to say that smaller, older boilers can or would not be converted to burn CWM. However the impact of those conversions on potential oil displacement would be minimal and is not investigated as part of Phase II.

More than one quarter of oil-fired boilers in Regions 1, 2, 4, and 9 fit into the categories of age and size previously mentioned.[4] These units can be separated into three classifications (see Table A-2): those designed for coal and currently burning oil; those designed for oil but with a configuration similar to a coal-designed unit (designated as Type 1); and those designed for oil without allowances for potential conversion to coal-firing (designated as Type 2).

The first two classifications of units, coal designed and Type 1, are considered suitable for conversion to CWM-firing. Type 1 boilers generally have larger furnace volumes and wider superheater tube spacing than Type 2 units, and are provided with space for coal handling systems; both of which are advantageous for conversion.[5]

Coal-designed and Type 1 unit populations in Regions 1, 2, 4, and 9 are shown in Table A-3. These units represent 101 of a total of 304 boilers larger than 50 MWe and younger than 25 years old (in 1985). The present electric output and capacity factors, on a regional basis are included on Table A-3. It is assumed that all 101 units can, and would, be converted to burn CWM in the event of an oil cut-off. Coal-designed, oil-fired boilers that fit the selection criteria for CWM conversion but are not included in Table A-3 are those that have received a Notice of Effectiveness (NOE).[6] The receipt of an NOE indicates that a schedule has been established for reconverting to coal.

b. Industrial Sector

The regional distribution of projected oil use in the industrial sector (boilers over 50 x 10^6 Btu/hr) is not as skewed as that of the utility sector. However, the Western and Midwestern Regions 7, 8, 9 and 10, account for less than eight percent of projected oil consumption.[1] (See Table A-4.) Boilers in these regions are not considered for conversion to CWM-firing due to their small requirement for CWM which would not justify the construction of a central CWM preparation

plant. However, Regions 1 through 6 will require a significant amount of CWM which will necessitate the construction of one or more central preparation plants per region. The impact of CWM conversions in these regions is assessed as part of Section 3.

Based on available data, a regional distribution of boilers has been estimated. The number of boilers and total capacities per region, shown in Table A-4, have been derived from OTA oil projections. Variances per region in average boiler capacities for units larger than 50 x 10^6 Btu/hr would affect some of these figures but not to the degree where Regions 7 through 10 would become significant. A nationwide average boiler size of 135 x 10^6 Btu/hr, for units larger than 50 x 10^6 Btu/hr, is assumed to be consistent among the various regions and is employed as a "reference" boiler size for the purposes of this study

Boilers smaller than 50 x 10^6 Btu/hr have not been considered, partially because of the relatively higher cost of conversion resulting in diseconomies of scale. In addition, the 141,500 units smaller than 50 x 10^6 Btu/hr, (more than 30 times the number of boilers larger than 50 x 10^6 Btu/hr) are expected to consume only 20 percent more oil than all larger boilers.[7] It is obvious that converting 141,500 to displace virtually the same amount of oil as burned by 4,400 units, is impractical. It is expected that the smaller boilers will most effectively contribute to oil displacement by converting to natural gas, which is a less complex and less costly conversion (see Appendix D). Although not considered for conversion to CWM-firing, some small boilers could be expected to convert to CWM but their impact on oil displacement would be small compared to larger units.

3. IMPLEMENTATION OF CWM CONVERSIONS

a. Utility Sector

1) Oil Displacement Potential

The burning of CWM in a previously oil-fired boiler will result in some derating of the boiler's output capacity. The increased ash loading in the gas stream requires that gas velocities be reduced in order to minimize erosion. This decrease in velocity, in addition to lower adiabatic flame temperatures of CWM, could result in a derated capacity as low as 50 percent; however, not all

boiler will experience such a severe derating.[8] For the purposes of this study, we have assumed that a boiler will operate at a conservative figure of 55 percent of capacity.[9, 10]

This derating assumes that coal used to prepare CWM is not beneficiated. If coal were to be cleaned such that the ash content could be reduced to less than one percent, some units would only be derated to 80 to 95 percent of capacity. However, there would be little incentive to beneficiate because, as will be shown, adequate capacity is available to make up for lost capacity because of derating to 55 percent.

The capacity factor (actual boiler operating hours as a percent of theoretical maximum) of units converted to CWM-firing are expected to increase to 60 percent. This figure is usual and normal for units presently burning coal.[11] Table A-5 reflects the anticipated electric output of derated units operating at higher capacity factors. The oil displacement potential of burning CWM is derived from these electric output figures as compared to the projected electric output of oil-fired boilers. (See Table A-1.)

This method of determining oil displacement potential assumes that excess capacity is available. As discussed in Phase I, Exhibit B-1-1, significant projected reserves in electric generating capacity are expected. Some generating stations, unable to tie into this excess capacity, might have to switch back to oil-firing temporarily to meet peak demand periods. However, this oil use is not anticipated to be significant compared to the projected 430,000 bbl/day displacement.

2) CWM Preparation Plants

Presently, CWM is commercially available for testing and demonstration purposes from several suppliers. For example, Atlantic Research Corporation, sells its CWM product under the trademark ARC-COAL. For the purposes of this study, ARC-COAL has been considered representative of CWM.[12] The physical and thermodynamic characteristics of CWM employed in this study are listed in Table A-6. Based on these figures a projected CWM use by Region is determined as discussed below.

The consumption of CWM by boilers identified in section 2.a. is expected to be considerable enough to warrant an individual, on-site, preparation plant for each unit. Based on average unit sizes per region (see Table A-5), a daily CWM consumption of approximately 8000 bbl was determined. Assuming a preparation plant capacity factor of 80 percent, a 10,000 bbl/day plant is required. For reliability and the advantages of standard size, two 5,000 bbl/day "modules", (individual facilities that could operate independently) would be expected to comprise the overall plant. Table A-7 shows the total number of modules necessary to supply required amounts of CWM. Note that these figures are twice the number of converted boilers (see Table A-5). A schematic presentation of a CWM module is included as Figure A-1.[13] All module components would be sized for either 5,000 bbl/day of CWM or 75 tons/hr of coal.

Since the majority of boilers identified for conversion are clustered together in groups of two or three (or more) per site, it is expected that pairs of modules would be grouped accordingly. In order to determine the number and sizes of coal handling systems needed to supply CWM modules, present distributions, by Region, of utility boiler groupings were examined. The result, displayed on Table A-7, indicates that the 101 converted boilers will require 65 CWM preparation plants, consisting of from 2 to 12 modules.

Each preparation plant requires a coal handling system as shown in Figure A-2.[14] The equipment would be sized for 75 tons/hr (two module plant) to 200 tons/hr (six module plant).

On-site modular CWM preparation plant deployment is considered because it offers a worst case scenario with respect to potential constraints. Large mine mouth CWM preparation plants might be more economical to build and operate under non-crisis conditions, as studies by Foster Wheeler Corp. have indicated. However, these large plants (approximately the size of twelve modules) would require more lead time to construct as well as the necessary involvement of a third party to bring together several interested utilities. These factors, although not particularly disadvantageous with respect to present business conditions, might

slow down implementation of CWM use in the utility sector in the event of an oil disruption.

3) Boiler Modifications

Virtually all of the possible boiler modifications are in response to increased ash loading in the gas stream. These include:

- Additional soot blowers to minimize ash deposition on furnace walls and convection pass surfaces,
- New, steeper, ash hoppers to accommodate increased amounts of ash,
- Installation of particulate control system (PCS) to meet air quality standards,
- Replacement induced and forced draft fans sized for new gas flow and PCS pressure drop,
- Modification or replacement economizer tubing to permit deposit removal, and
- Installation of ash handling system.

The abrasive nature of CWM in liquid form might necessitate replacement (or modified) fuel pumps and burners with wear resistant materials.[8][9]

In terms of air quality, an increase or change in atmospheric pollutants may result by converting oil units to CWM. Boilers that undergo conversion or modification will still be required to meet applicable Federal, State and local air quality regulations. (Although converted units may not have to meet New Source Performer standards.) On the Federal level, National Ambient Quality Standards (NAAQSs), primary and secondary (more stringent), have been established for Air Quality Control Regions (AQCRs)

Three pollutants, total suspended particulates (TSP), sulfur dioxide (SO_2), and nitrogen oxide (NOx), are associated with fossil fuel fired boilers. For TSP, SO_2 and NOx an area is classified as either "non-attainment", if NAAQSs (primary, secondary or both)* are being exceeded,

* Primary and secondary for NOx are identical.

or "attainment", if all NAAQSs are satisfied (i.e. maximum limits of time averaged concentration of pollutants are not exceeded). The attainment status of an area is usually an influencing factor in determining the environmental acceptability of fuel conversion. In nonattainment areas, regulatory problems would most likely be more consequential than in attainment areas.

With regards to the location of utility boilers in nonattainment areas, only a small percentage of coal designed and Type 1 units are located in areas designated as nonattainment for SO_2. In addition, there is only one boiler in a nonattainment area for NOx. However, about 25 percent of coal-designed boiler capacity and 45 of oil-designed boiler capacity is located in nonattainment areas for TSP.[15] Particulate control, therefore, is included as a likely boiler modification.

Flue gas desulfurization (FGD) has not been considered, in part, because of the density of boilers in SO_2 nonattainment areas. However, some boilers may require FGD systems and this impact is excluded for emergency conversion purposes.

As shown in Table A-6, it is assumed that low sulfur coal (less than one percent) will be used in preparing CWM; and sufficient bituminous low sulfur coal is available for this purpose. The utilization of low sulfur coal is another justification of omitting FGD systems from anticipated modifications to converted boilers. However, in light of assumed coal characteristics, particulate control systems (PCSs) will be necessary.

4) Schedule of Engineering and Construction

The item with the longest lead time (time from order to delivery) when modifying a utility boiler is the particulate control system (PCS) (see Figure A-3). An estimated procurement period of 15 months comprises more than half of the 27 months from the start of engineering to the start-up. The next longest lead time belongs to the coal handling system of the on-site CWM preparation plant, the schedule of which is assimilated into that shown in Figure A-3.

It should be noted that in the schedule, Figure A-3, permitting starts simultaneously with engineering. It is assumed that in the advent of an oil crisis, the regulatory climate will be relaxed enough to allow such a procedure. However, construction (site preparation) would not begin until a building permit had been obtained.

Four months of initial engineering and seven months of construction are required before the order and after the delivery, respectively, of all equipment. Given a five year time period within which to convert all identified utility boilers, it is apparent that deliveries of equipment can be staggered over four years. This fact is important when assessing the ability of manufacturers to supply needed equipment (addressed in Section 3).

b. Industrial Sector

1) Oil Displacement Potential

In light of limited data available pertaining to individual industrial boilers, an overall figure of 50 percent was used to arrive at regional oil displacement figures. A 50 percent penetration of CWM conversions into the oil-fired boiler market is assumed to be the upmost maximum that could be reached considering the age profile, available space for ash handling and particulate control systems, and geographic distribution of existing boilers. Although it is expected that less than half of the 1985 projected oil use of large industrial boilers will be displaced by CWM conversions, potential constraints of implementation will be more apparent if the largest penetration is considered.

Potential regional oil displacement figures are listed in Table A-8. The amounts were determined based on the aforementioned penetration assumption. The number of boiler conversions are derived from the oil displacement figures and average boiler oil consumption. The capacity of each boiler is assumed to drop to the same level estimated for utility boilers, 55 percent. Although utilities can make-up some of this derating with reserve capacity, industrial firms will most likely need an additional boiler to meet steam requirements.

Industrial firms usually have some reserve capacity. Most industries generate steam by cycling two or more units such that at least one boiler is always available as a reserve. This is done to allow for scheduled and unscheduled repairs and maintenance. In the initial stages of a crisis, cycling could be forestalled in order to adjust for derating associated with CWM conversion. But system reliability could not be compromised indefinitely and new CWM-fired boilers would ultimately have to be purchased. Based on an average boiler size of 135×10^6 Btu/hr, a new CWM-fired unit with a capacity of 50×10^6 Btu/hr would be necessary to account for the expected derating.

2) CWM Preparation Plants

Individual consumption of CWM by industrial users is expected to be too small to warrant on-site CWM preparation plants. Instead, industrial boilers can be most effectively served by central plants, two or three per region. Distribution of CWM would be through existing oil delivery networks. Some minor modifications to existing nozzles and pumps would be required.

Based on projected values of CWM consumption (see Table A-8), and a CWM module size of 5000 bbl/day, numbers and sizes of preparation plants were determined (see Table A-8). These plants would be either four or six modules and are identical to plants required by utility boilers. (See Section 3.a.) A total of 76 modules would be necessary to constitute 15 plants in the selected region. Each plant would consist of a coal handling facility and a group of CWM modules (see Figures A-1 and A-2).

3) Boiler Modifications

Boiler modifications of industrial boilers would be the same as those outlined for utility units. (See Section 3.a.) A summary of equipment and modifications required to convert oil-fired industrial boilers (as well as utility units) to CWM-firing is presented in Table A-9. Also included are characteristics, sizes and components of CWM preparation plants.

4) Engineering and Construction Schedule

Figures A-4 and A-5 illustrate the length of time estimated for constructing central CWM preparation plants and modifying boilers, respectively. Each preparation plant is expected to take 18 months to construct if the permitting process and engineering begin simultaneously. Industrial boiler modifications (see Figure A-5) should not require as much time as those required for utility units but new boilers must be ordered and erected. This results in a total estimated time of engineering and construction of 21 months. The boiler and PCS are the items with the longest lead times, 10 and 12 months, respectively.

4. ASSESSMENT OF POTENTIAL CONSTRAINTS

The following areas were investigated to determine the extent of any possible constraints that might impede deployment of CWM conversions in the utility and industrial sectors.

a. Coal Availability

Based on projected use of CWM (see Tables A-7 and A-8), annual coal requirements were determined as shown on Table A-10. It is apparent that CWM conversions will prompt a marked increase in coal demand in Regions 1, 2, and 9. However, the total increase in national coal production is expected to be less than 10 percent. Since low sulfur bituminous coal is required, most of the increased production will be in Appalachian areas. (Western regions have abundant low sulfur coal but virtually all of it is too moist to achieve high enough coal loadings when preparing CWM.) Demonstrated reserve figures indicate that over $30,000 \times 10^6$ tons of low sulfur bituminous coal are available (See Table A-10), of which over 290×10^6 tons are produced per year.[25] With a requirement of 63.8×10^6 tons/yr, CWM preparation would necessitate a 22 percent increase over present production levels. This represents a 10 percent annual growth rate compounded over the two year deployment period. The transportation of this coal to the regions identified on Table A-10 has been shown in Phase I of this report to be feasible.

b. Coal Handling System

A total of 80 coal handling facilities will be necessary to supply CWM preparation modules (see Table A-9). These systems are expected to vary in size from 75 to more than 200 tons per hour. Discussions with a prominent materials handling system assembler indicated that the industry could produce sixty large sized (100-200 tph) systems easily in one year. Only one piece of equipment was singled out as having the remotest potential to slow production of handling facilities. This item, conveyor idler bearings, would only have an impact however, if all other markets for idler bearings were similar taxed, which would be highly unlikely.[16]

c. CWM Preparation

Presently, the preparation of CWM is in a demonstration phase. Various programs, supported by EPRI and DOE, are under way and commercial preparation is expected by 1985[17]

To date, no large scale CWM preparation plant has been built. However, the technology is being demonstrated and according to the manufacturers of ARC-COAL, "a 100,000 bbl/day production plant can be constructed and operational in 1985." The equipment that comprises a CWM preparation module (see Figure A-1) consists of only basic items. The tanks, pumps, mills, and silos required to constuct 278 5000 bbl/day modules over five years are expected to be readily available. Present sales of equipment in this size range far exceed the anticipated increase in demand associated with CWM preparation. Also, the fact that all modules will be identical, will facilitate, to a greater degree, the manufacture and supply of required equipment.

d. Boiler Conversion

Historically, the boiler industry has sold as many as 350 electrical generating units, over a five year period, to foreign and domestic utilities.[18] It is assumed that the industry, in light of its track record, can produce the equipment necessary to modify 101 utility boilers over a five year period. Combustion Engineering, one of the largest manufacturers, felt that their firm alone could perform all of the conversions over a three year period.[19] With respect to PCSs for each unit, one of the ten major suppliers of PSCs stated

that 101 units could be manufactured easily by the industry.[20]

Conversions of industrial boilers would not be as involved as those of utility units. However, more than 900 particulate control systems will be required if maximum penetration is achieved. According to the Industrial Gas Cleaning Institute (IGCI), during 1980 the year with the largest number of bookings, 200 units were sold. The IGCI felt that the industry could meet the challenge of producing 1000 units over a three year period.[21] This was confirmed by a major manufacturer which stated that they could produce nearly half of the required units over a three year period.[22]

Conversion of industrial boilers to burn CWM will require more than 900 new "solid fuel" (i.e. CWM) fired boilers. The average size of these boilers is expected to be 50 x 10^6 Btu/hr. Historically the manufacture of solid fuel boilers has been limited; sales of one hundred units, in 1973, sized from 10 to 100 x 10^6 Btu/hr, was the most recent high.[18] However, when gas- and oil-fired units are included, more than 800 boilers in the 10 to 100 x 10^6 Btu/hr size range, have been sold in one year. In the event of an oil disruption it is assumed that oil and gas boiler capacity can be utilized to manufacture CWM-fired units. This logic has been confirmed by several manufacturers of industrial boilers which stated that the limiting constraint in producing a boiler is the steam drum and that this component does not significantly differ with respect to fuel used.[18,19,23,24]

e. Ash Disposal

Assuming an average ash content of 5 percent for all coal now being consumed, ash disposal figures on a regional basis have been determined (see Table A-11). Regions 1, 2, and 9, in the event of a 50 percent penetration of CWM conversions in the industrial sector and utility use of CWM, would exhibit significant increases in ash to be disposed of. Table A-11 illustrates that the total increase in ash dispoal, on a national basis, would be less than ten percent. But the increase in Region 2 is more than 100 percent and in Region 1 the increase is seven times larger than present figures.

However, it is assumed that in the event of a crisis, ash disposal will not constrain the implementation of CWM conversions. The disposal of ash, being a fully

institutional constraint, could be allowed with less permitting required.

5. RATE OF OIL DISPLACEMENT

It was shown in Section 4 that there are no serious impediments in converting boilers to burn CWM. It is expected that oil displaced by converting could reach anticipated levels (see Tables A-5 and A-8). The rate of this displacement will be governed by the availability of PCS's since this equipment has been determined to be the most difficult to supply. Figure A-6 illustrates, separately, the rates of oil displacement for the industrial and utility sectors. The initial displacement values are based on the historically highest supplies of PCS's and schedules of conversion (see Figures A-3 through A-5).

The greatest number of utility sized PCS's supplied in one year was 50. As shown on Figure A-6, this indicates that one half of the total oil displacement potential of the utility sector would be realized after the first conversions were completed. The remaining PCS's required could be supplied 15 months later (see Figure A-3), thereby completing all of the necessary conversions within four years.

Industrial boiler PCS equipment, according to manufacturers (see Section 4), could be supplied to 1000 boilers in 3 years. Assuming that the first year's production would not exceed the greatest output to date (200 units), less than a third of the potential oil displacement could be achieved initially (See Figure A-6). In order to supply the required number of PCS's, manufacturers would have to increase output at a rate of nearly 50 percent. This delivery rate is reflected on the displacement curve for the industrial sector shown on Figure A-6. The addition of this displacement rate to that of the utility sector is shown on Figure A-7.

5. REFERENCES

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(4) Ibid, pp 5-6, 22, 29-48.

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(7) "Population and Characteristics of Industrial Boilers in the U.S.," EPA 600/7-79-178A, pp 13-14, 1979.

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(14) Steam, Babcox & Wilcox, New York, New York, pp 8-1 to 8-16, 1978.

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(16) Edwards, E. (Dravo Engineers Inc.). Personal communication with N. Hinsey (Gibbs & Hill, Inc.), March 8, 1983.

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(25) "Sulfur Content in Coal Shipments, 1978," U.S. DOE, Coal Statistics Division, DOE/EIA-0263(78), June 1981.

TABLE A-1

PROJECTED (1985) OIL CONSUMPTION AND ELECTRIC OUTPUT OF UTILITY BOILERS IN STANDARD FEDERAL REGIONS 1, 2, 4 AND 9

Region	Number (a) of Boilers	Total Capacity (MWe)	Projected 1985 Oil Use (b) (bbl/day)	Total Electric Output (c) (MWh/Yr)	Oil Capacity Factor (c) (%)
1	290	12,964	174,000	32,780,000	29
2	342	28,853	168,000	31,670,000	13
4	456	30,826	81,000	15,240,000	6
9	374	29,132	97,000	18,170,000	7
	1,462	101,775	520,000	97,860,000	11

Notes:

(a) Includes all boilers, regardless of age or size, now burning oil (1980).

(b) OIA projections of residual oil consumption of all units regardless of age or size.

(c) Based on OIA projected oil consumption and a heat rate of 10,669 Btu/kWh.

Sources:

"Inventory of Power Plants in the U.S." 1980, DOE EIA 0095, and EIA Form 759, "Utility Oil Use and Profile for 1981."

TABLE A-2

COMPARISON OF COAL-DESIGNED AND OIL-DESIGNED (TYPE 1 AND TYPE 2) UTILITY BOILERS

FEATURES	"Type 1" Oil-Designed	"Type 2" Oil-Designed	Coal-Designed
--Similar to coal-designed boiler configuration	Yes	No	N.A.
--Furnace Heat Release Rate (1000 Btu/Cu-Ft/Hr)	13-26	22-31	9-22
--Furnace Exit Gas Temp. (°F)	2050-2300	2200-2600	2000-2300
--Superheater Tube Spacing (first row)	12"-18"	6"-12"	12"-24"

Note:

N.A. = Not applicable

Source: "Survey of Oil-fired Utility Boilers, DOE/FE/53179-01, February 1980.

TABLE A-3

PROFILE OF UTILITY BOILERS (OVER 50 MWe) PRESENTLY BURNING OIL IDENTIFIED FOR CWM CONVERSION

Region	Boilers Designed for Coal Currently Burning Oil (a) (b)					Boilers Designed for Oil Currently Burning Oil (a) (c)				
	Number of Boilers	Total Capacity (MWe)	Total Output (MWh/Yr)	Capacity Factor (%)	Average Capacity (MWe)	Number of Boilers	Total Capacity (MWe)	Total Output (MWh/Yr)	Capacity Factor (%)	Average Capacity (MWe)
1	16	4,323	18,150,000	48	270	6	2,489	9,550,000	44	415
2	16	5,403	8,700,000	18	338	9	4,323	13,250,000	35	480
4	4	1,224	1,725,000	16	306	20	6,775	23,521,000	40	339
9	-	-	-	-	-	30	9,353	15,000,000	18	312
TOTAL	36	10,950	28,575,000	30	304	65	22,940	61,321,000	31	353

Notes:

(a) Includes only those boilers that will be less than 25 years old in 1985 and larger than 50 MWe.

(b) Excludes boilers that have received a Notice of Effectiveness (indicating that a schedule has been established for reconverting to coal).

(c) Includes only Type 1 boilers; ("Type 1" refers to those boilers which have characteristics similar to coal-designed boilers and require less capital investment for conversion compared to Type 2 boilers, which are distinctly different from coal-designed units).

Sources:

DOE/FE/53179-01, "Survey of Oil Fired Utility Boilers," February 1980.

EIA, Form 759 "Utility Oil Use and Profile for 1981."

TABLE A-4

PROJECTED (1985) REGIONAL OIL CONSUMPTION OF INDUSTRIAL BOILERS WITH CAPACITIES LARGER THAN 50 X 10^6 BTU/HR

Region	Number of Boilers	Total Capacity (10^6 Btu/hr)	Projected 1985 Oil Use		
			Residual (bbl/day)	Distillate (bbl/day)	Total (bbl/day)
1	559	75,076	44,000	8,000	52,000
2	988	132,692	74,000	18,000	92,000
3	408	54,796	32,000	6,000	38,000
4	913	122,620	79,000	6,000	85,000
5	451	60,571	36,000	6,000	42,000
6	709	95,222	58,000	8,000	66,000
7	59	7,924	3,500	2,000	5,500
8	110	14,773	9,000	1,250	10,250
9	102	13,699	7,000	2,500	9,500
10	62	8,327	4,500	1,250	5,750
TOTAL	4,361	585,700	347,000	59,000	406,000

Sources:

"Population and Characteristics of Industrial Boilers in the U.S." EPA/600/7-79-178A, 1979;

OTA projections for 1985

TABLE A-5

DAILY REGIONAL OIL DISPLACEMENT POTENTIAL OF UTILITY BOILERS CONVERTED TO CWM-FIRING

Region	Number (a) of Boilers	Present Total Capacity (a) (MWe)	Derated Boilers Burning CWM (b)			
			Total Capacity (MWe)	Average Capacity (MWe)	Total Electric Output (c) (MWh/Yr)	Oil Displaced by CWM (d) (bbl/day)
1	22	6,812	3,746	170	19,692,000	104,527
2	25	9,726	5,349	214	28,113,000	149,131
4	24	7,999	4,399	183	23,121,000	81,000
9	30	9,353	5,145	172	27,041,000	97,000
TOTAL	101	33,889	18,639	185	97,967,000	431,658

Notes:

(a) See Table A-3

(b) Derated to 55 percent of present capacity

(c) Based on capacity factor of 60 percent

(d) Estimates derived from projected electric output and oil use (see Table A-3)

TABLE A-6

ASSUMED CHARACTERISTICS OF COAL WATER MIXTURE (CWM)

CWM	
Composition*:	70% Coal 30% Water
Weight:	10 lb/gal
Btu Value:	95,000 Btu/gal or 4×10^6 Btu/bbl

COAL**	
Type:	Bituminous
Higher Heating Value:	13,570 Btu/lb
Volatiles:	> 20%
Ash:	< 7%
Sulfur:	< 1%
Size:	50 mesh x 0

* Weight %; additives constitute less than one percent.

** All percentages by weight, dry basis.

TABLE A-7

REQUIRED ON-SITE CWM PREPARATION PLANTS FOR CONVERTING UTILITY BOILERS TO CWM-FIRING

Region	Oil Displaced by CWM (a) (bbl/day)	Projected CWM Use (b) (bbl/day)	On-Site CWM Preparation Plants (c)			
			Total (d) Modules	2 Module Plants	4 Module Plants	6 Module (or larger) Plants
1	104,527	177,204	44	11	4	1
2	149,131	252,983	50	9	6	1 (e)
4	81,000	208,061	48	14	5	0
9	97,000	243,337	60	5	6	3 (f)
TOTAL	431,658	881,585	202	39	21	5

Notes:

(a) See table A-5

(b) Based on reduced boiler efficiency and 60 percent capacity factor

(c) Estimated 80 percent capacity factor

(d) 5000 bbl/day of CWM capacity per module

(e) 8 module plant

(f) Includes one 8, and one 12 module plant

TABLE A-8

DAILY REGIONAL OIL DISPLACEMENT POTENTIAL, REQUIRED BOILER CONVERSIONS AND CENTRAL CWM PREPARATION PLANTS FOR CONVERTING INDUSTRIAL BOILERS TO CWM-FIRING

Region	Total (a) Projected 1985 Oil Use (bbl/day)	Oil Displaced (b) by CWM Conversion (bbl/day)	Number of (c) Boilers Converted	Projected CWM Use (d) (bbl/day)	Central CWM Preparation Plants (e)		
					Total (f) Modules	4 module Plants	6 module Plants
1	52,000	26,000	126	41,900	10	1	1
2	92,000	46,000	223	74,100	18	-	3
3	38,000	19,000	92	30,600	8	2	-
4	85,000	42,500	206	68,400	16	1	2
5	42,000	21,000	102	33,800	10	1	1
6	66,000	33,000	160	53,200	14	2	1
TOTAL	375,000	187,500	909	302,000	76	7	8

Notes:

(a) See Table A-4

(b) Based on 50 percent penetration estimate

(c) Average boiler size is assumed to be 135×10^4 Btu/hr with a 35 percent capacity factor

(d) Based on reduced boiler efficiency and 4×10^4 Btu/bbl CWM

(e) Assumed capacity factor of approximately 80 percent

(f) 5000 bbl/day CWM capacity per module

TABLE A-9

EQUIPMENT AND MODIFICATIONS POSSIBLY REQUIRED TO CONVERT OIL-FIRED INDUSTRIAL AND UTILITY BOILERS TO CWM-FIRING

EQUIPMENT OR MODIFICATION	UTILITY		INDUSTRIAL	
	CAPACITY	QTY.	CAPACITY	QTY.
Boiler Modifications - Replacement Burners and Fuel Pumps - Additional Soot Blowers and Bottom Ash Hopper - Modification or Replacement of Economizer Tubing - Replacement Induced and forced Draft Fans	185 MWe	101	61×10^4 Btu/hr	909
New CWM-Fired Boiler	-	-	50×10^4 Btu/hr	909
Particulate Control System	285,000 scfm	101	35,000 scfm (a)	909
Ash Handling System (b)	3.5 tph (6675 lbs/hr)	101	820 lbs/hr (a)	909
Coal-Water Mixture Preparation Module - Coal Silos, feeders - Rod Mill, Ball Mill - Storage and Mixing Tanks - Water and CWM Pumps	5,000 bbl/day	202	5000 bbl/day	76

TABLE A-9 (cont'd)

EQUIPMENT OR MODIFICATION	UTILITY/INDUSTRIAL CAPACITY	QTY.
Coal Handling Facilities		
- Track Hopper Weigh Scale	2 Module 75 tons/hr	39
- Raw Coal and Crushed Coal Conveyors	4 Module 150 tons/hr	28
- Coal Crushers, Transfer Houses	6 Module 200 tons/hr	13
- Sampling System, Live and Dead Storage Piles		

Notes:

(a) Sized to accommodate derated and additional new boiler

(b) Based on 7% ash coal; includes disposal

TABLE A-10

PRESENT COAL CONSUMPTION AND DEMONSTRATED RESERVES COMPARED TO CWM COAL REQUIREMENTS

	DEMONSTRATED RESERVES*			PRESENT COAL CONSUMPTION			CWM COAL REQUIREMENTS		
		BITUMINOUS							
REGION	LESS THAN 1% SULFUR (10^4 TONS)	(10^4 TONS)	% OF ALL RESERVES	ALL SECTORS (10^4 TPY)	UTILITY BOILERS (10^4 TPY)	INDUSTRIAL BOILERS (10^4 TPY)	UTILITY BOILERS (10^4 TPY)	INDUSTRIAL BOILERS (10^4 TPY)	TOTAL (10^4 TPY)
1	-	-	-	1.6	1.2	0.4	9.5	2.3	11.8
2	-	-	-	16.2	12.1	4.1	13.6	4.0	17.6
3	23,685.6	67,548.0	92	131.4	98.0	33.4	-	1.7	1.7
4	7,388.4	28,975.6	98	144.3	107.6	36.7	11.2	3.7	14.9
5	1,778.3	97,913.9	100	218.0	162.5	55.5	-	1.8	1.8
6	4,591.3	3,748.0	68	37.7	28.1	9.6	-	2.9	2.9
7	1.5	8,214.4	100	42.4	31.6	10.8	-	-	-
8	150,391.9	21,083.6	10	41.4	30.9	10.5	-	-	-
9	173.3	325.3	100	18.4	13.7	4.7	13.1	-	13.1
10	12,061.9	952.8	12	5.6	4.2	1.4	-	-	-
TOTAL	200,072.2	228,761.5	-	656.9	477.3	179.6	47.4	16.4	63.8

Sources: 1980 Keystone Coal Industry Manual, McGraw-Hill, NY, NY, 1980
"State Energy Data Report," US Energy Information Administration, April 1980

Statistical Abstract of the U.S. 1983, Section 20, Dec. 1982.

* Only reserves in measured and indicated categories as defined by the USBM and USGS and represents 100% of coal in place.

TABLE A-11

PRESENT AND PROJECTED ASH HANDLING REQUIREMENTS

REGION	PRESENT ASH HANDLING			CWM ASH HANDLING		
	UTILITY BOILERS (10^4 TPY)	INDUSTRIAL BOILERS (10^4 TPY)	TOTAL (10^4 TPY)	UTILITY BOILERS (10^4 TPY)	INDUSTRIAL BOILERS (10^4 TPY)	TOTAL (10^4 TPY)
1	.08	.03	.11	.67	.16	.83
2	.84	.29	1.13	.95	.28	1.23
3	6.86	2.34	9.20	-	.12	.12
4	7.53	2.57	10.10	.78	.26	1.04
5	11.38	3.88	15.26	-	.13	.13
6	1.97	.67	2.64	-	.20	.20
7	2.21	.75	2.96	-	-	-
8	2 16	.74	2.90	-	-	-
9	.96	.33	1.29	.92	-	.92
10	.29	.10	.39	-	-	-
TOTAL	33.41	12.57	45.98	3.32	1.15	4.47

FIGURE A-1
CWM PREPARATION PLANT
CWM MODULE

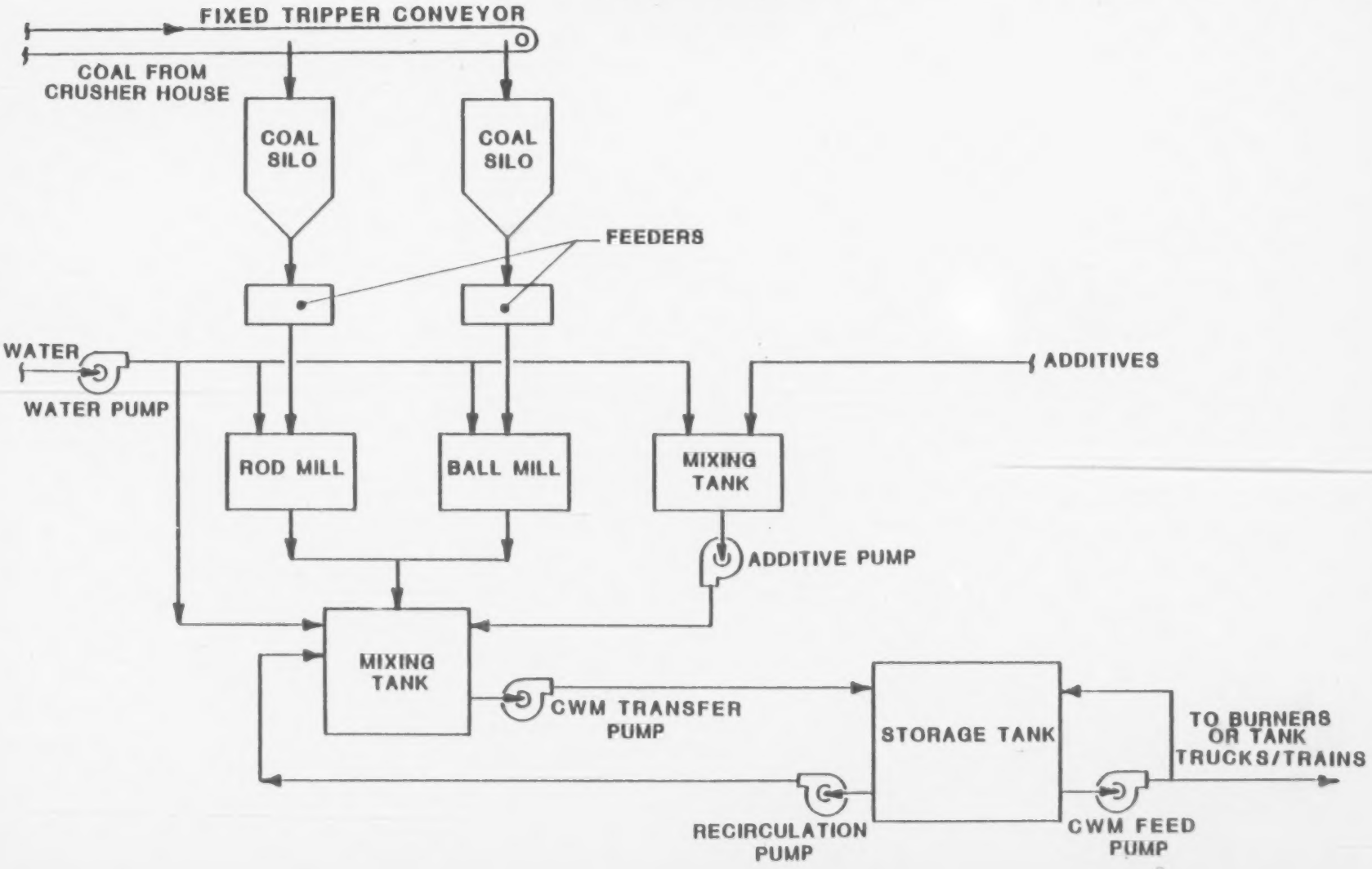


FIGURE A-2

CWM PREPARATION PLANT

COAL HANDLING SYSTEM

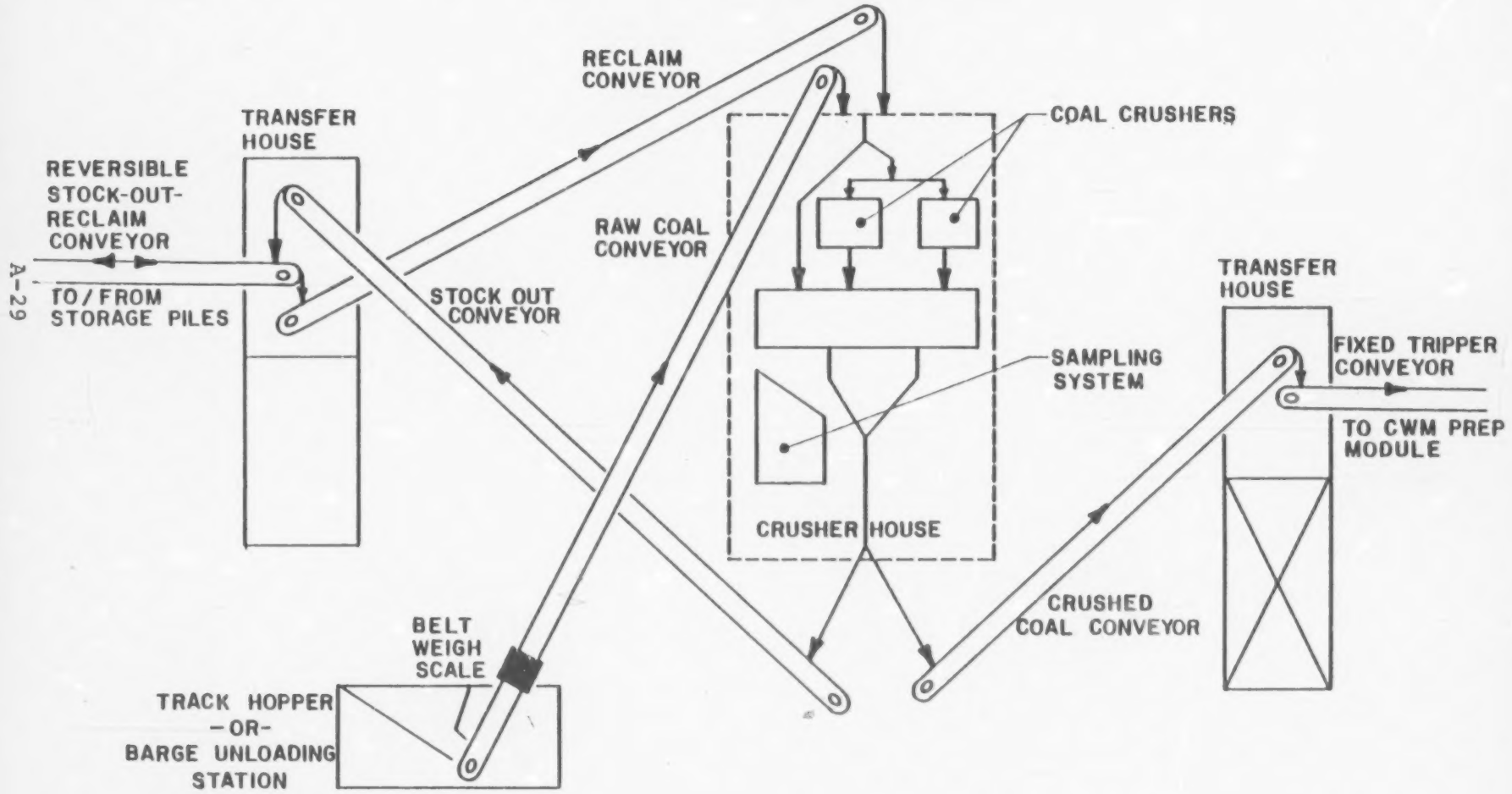
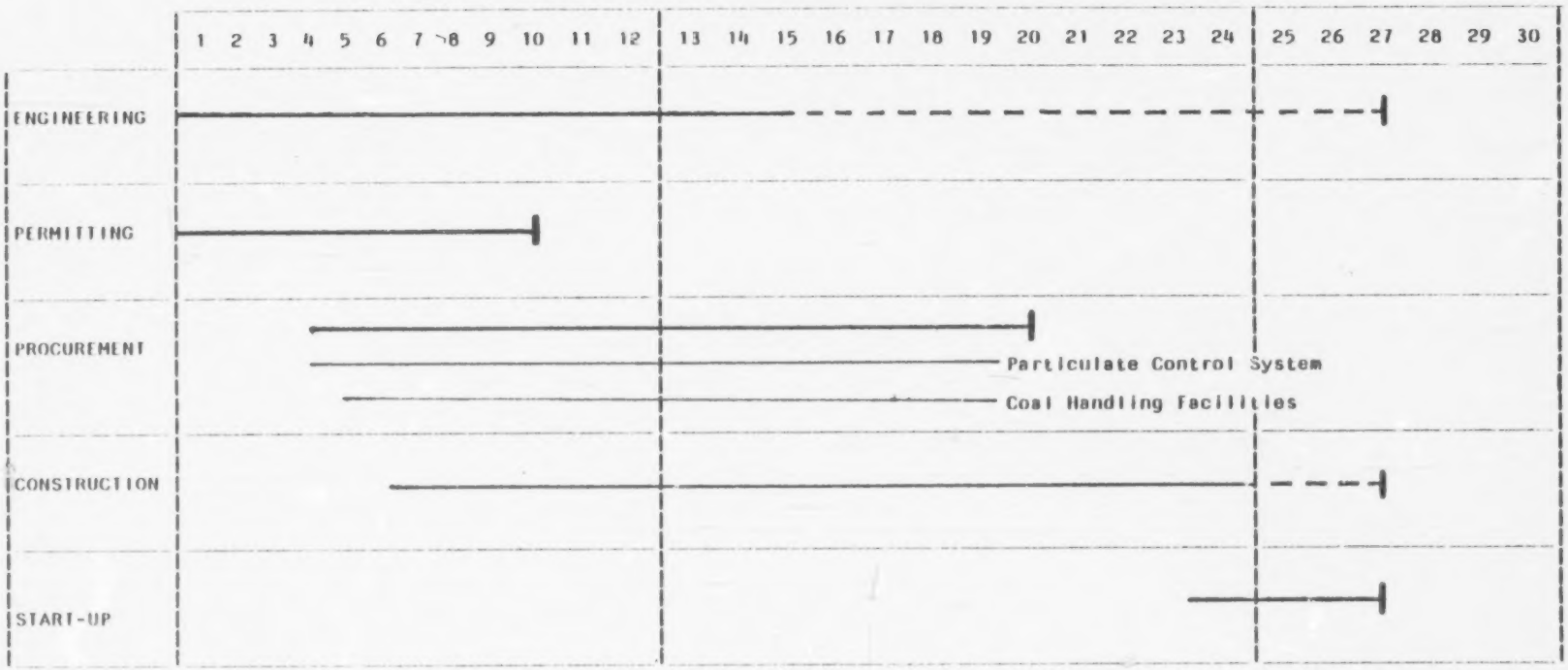


FIGURE A-3

SCHEDULE FOR ENGINEERING AND CONSTRUCTION:
UTILITY BOILER CONVERSION TO CWM-FIRING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ENGINEERING
PERMITTING
PROCUREMENT
Particulate Control System
Coal Handling Facilities
CONSTRUCTION
START-UP

FIGURE A-4

SCHEDULE FOR ENGINEERING AND CONSTRUCTION;
CENTRAL CWM PREPARATION PLANT FOR INDUSTRIAL BOILERS

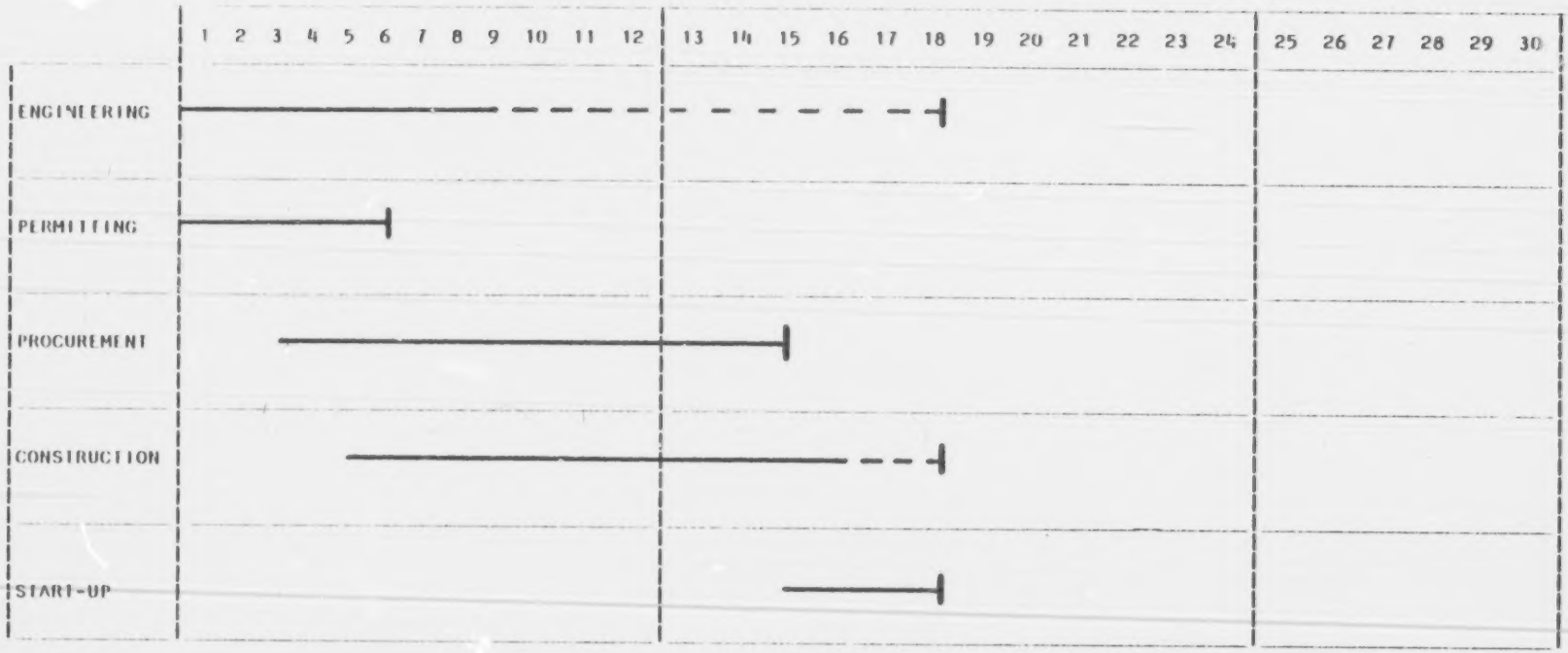
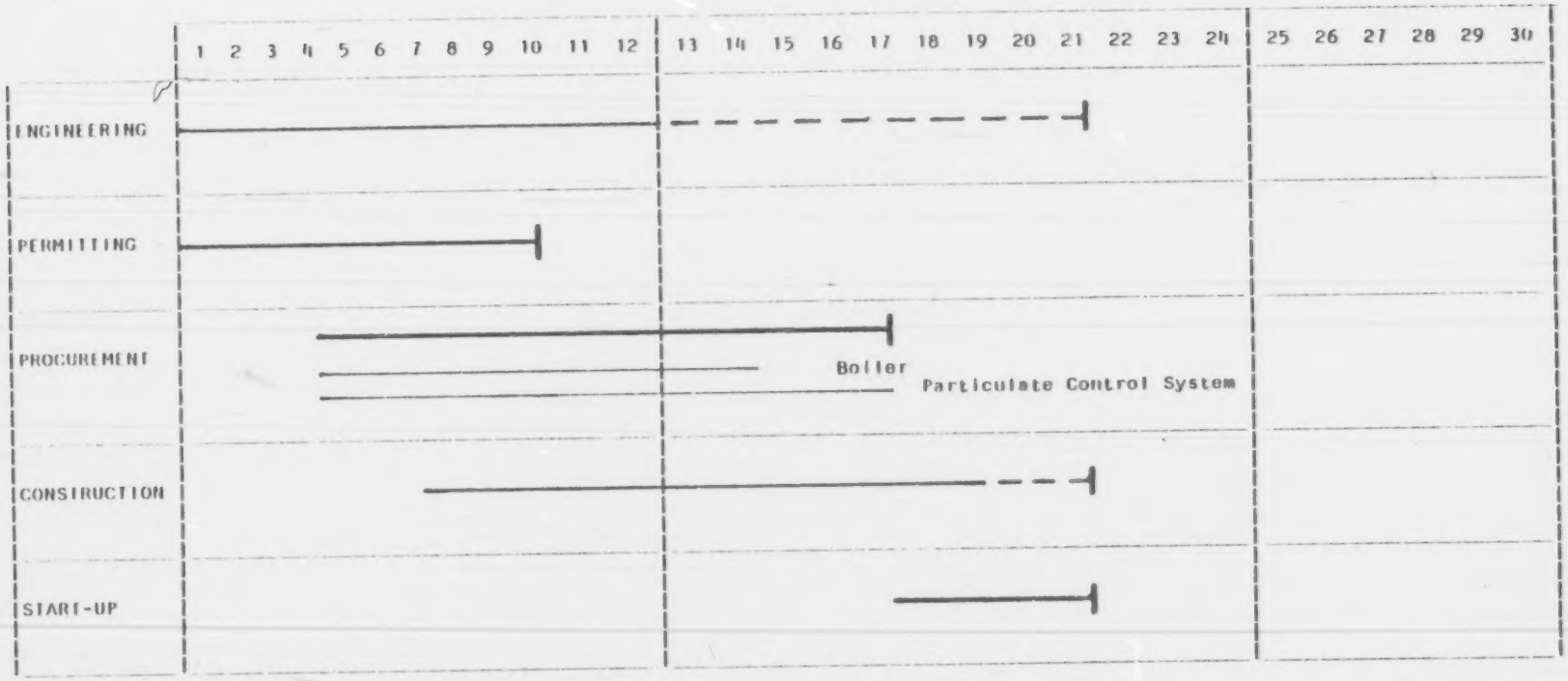


FIGURE A-5

SCHEDULE FOR ENGINEERING AND CONSTRUCTION:
INDUSTRIAL BOILER CONVERSION TO CWM-FIRING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ENGINEERING
PERMITTING
PROCUREMENT
Boiler
Particulate Control System
CONSTRUCTION
START-UP

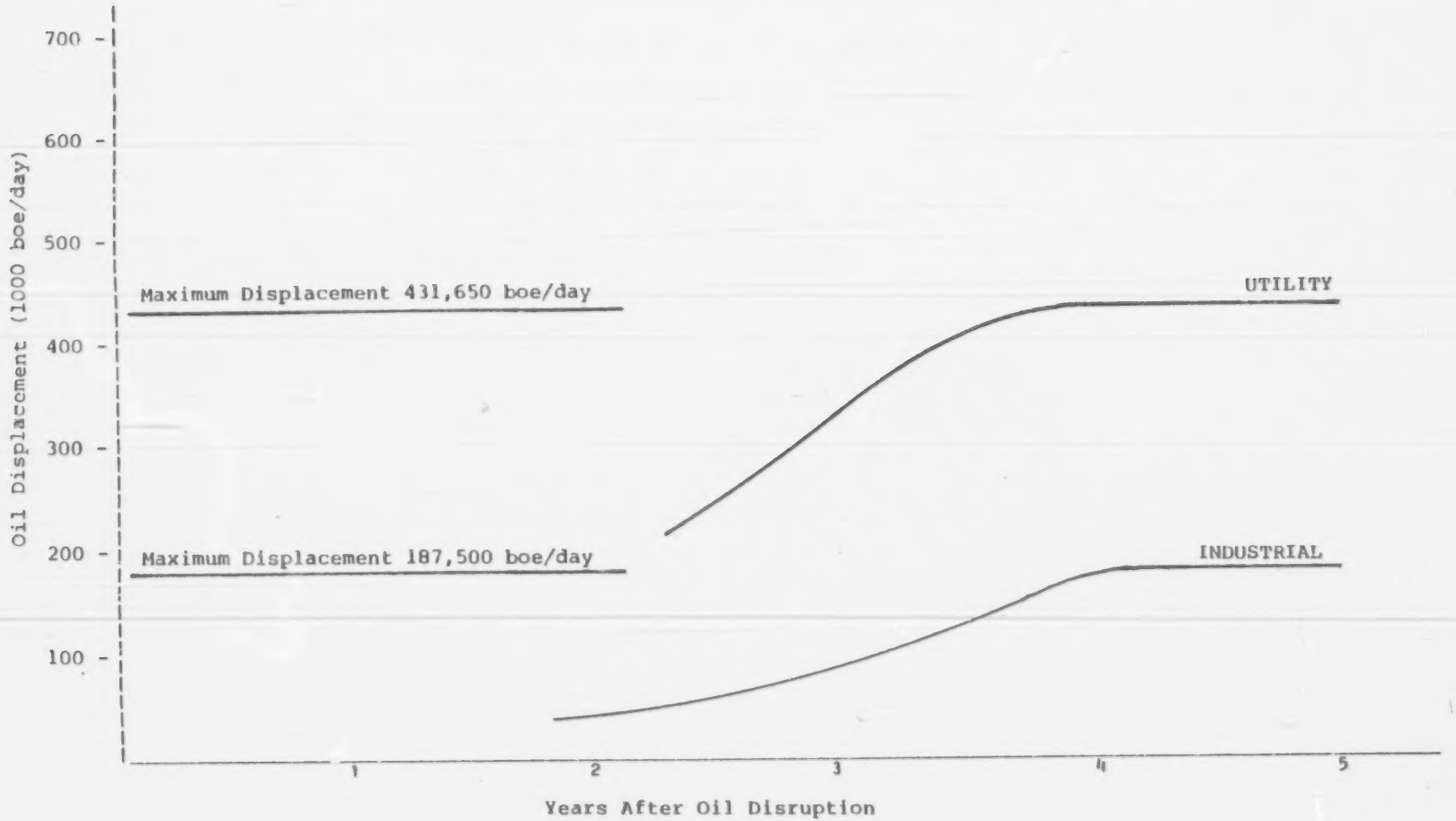

FIGURE A-6

RATE OF OIL DISPLACEMENT;
CONVERSION TO CWM IN THE INDUSTRIAL
AND UTILITY SECTORS

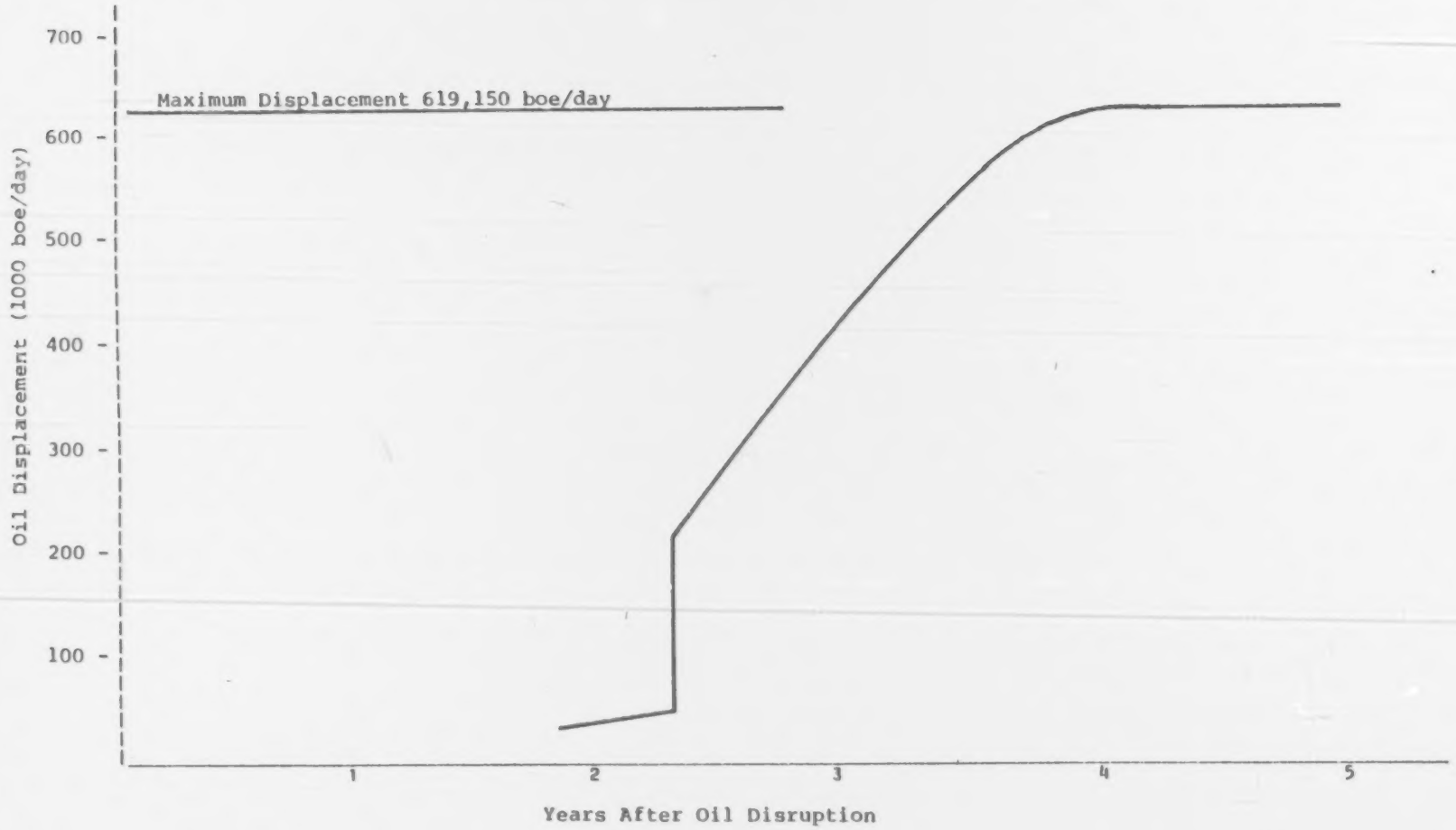

FIGURE A-7

RATE OF OIL DISPLACEMENT;
TOTAL OF CONVERSION TO CWM IN THE
UTILITY AND INDUSTRIAL SECTORS

B. WOOD AND COAL DIRECT COMBUSTION

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2. Projected Oil Use Profile

3. Implementation of Coal- and Wood-Fired Boilers

4. Assessment of Potential Constraints

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B-1 Projected Daily Regional Oil Displacement Potential for Direct Firing of Wood or Coal in the Industrial Sector

B-2 Annual Potential Wood Energy and Maximum Theoretical Daily Oil Displacement by Federal Region

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B-4 Equipment Required to Replace Oil-Fired Industrial Boilers with Direct Wood-Fired Units

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1. INTRODUCTION

The direct-firing of wood and coal in the industrial sector has been shown in Phase I to have significant oil displacement potential. These two options are further evaluated in this appendix utilizing the same industrial boiler base developed in Appendix A for CWM conversion in the industrial sector.

2. PROJECTED OIL USE PROFILE

As discussed in Appendix A, only industrial boilers larger than 50 x 10^6 Btu/hr are considered viable candidates for conversion, in this case, to direct coal- or wood-firing. (Conversion refers to the erection of a "slide-along" unit, described in Phase I, to burn the appropriate fuel.) Table B-1 summarizes the boiler population and projected oil use arrived at in Appendix A (see Table A-4). The same segment of the industrial boiler population has been selected to identify constraints assuming only one fuel will attain maximum penetration. Most likely, boilers will be converted in varying degrees to burn either CWM, coal or wood. However, unlike CWM conversions, coal and wood use by industrial boilers is expected to occur in all Federal Regions since central fuel preparation plants are unnecessary.

3. IMPLEMENTATION OF COAL- AND WOOD-FIRED BOILERS

The penetration of coal-fired boilers into the present oil-fired boiler population was assumed to be 50 percent in each region. The rationale for this penetration is discussed in Appendix A. As long as an industrial firm has enough space for a new boiler and for handling solid fuel, the possibility of converting to coal exists. The oil displacement potential of coal use and the number of new boilers required are shown in Table B-1. The number of boilers, 984, required to displace the amount of oil indicated in Table B-1, is based on an average boiler size of 135 x 10^6 Btu/hr and a 35 percent capacity factor.

The penetration of wood boilers into the industrial oil boiler sector, averaged over all regions, is slightly less than that of coal (see Table B-1). The energy density of wood is less than half the value for coal which makes the transportation of wood much more costly. Consequently, boilers not close to wood supplies could not economically justify switching to wood-firing. Therefore, regions where the number of boilers is small in comparison to the size of the region, reflecting long transportation distances, are

assumed to have smaller penetration percentages (i.e., Regions 7, 8, 9, and 10).

Table B-2 lists the maximum daily oil displacement potential of indigenous wood supplies of all Federal Regions. The wood supply potential of Region 2 is too small to sustain a 50 percent penetration into the oil boiler sector, thus the penetration estimate for Region 2 has been lowered to 20 percent such that the projected oil displacement is realistic in light of the maximum possible wood energy available.

Each new boiler, whether coal- or wood-fired, will require fuel and ash handling systems, and a particulate control system (PCS). For coal-fired units the average sizes of these systems, as well as lists of component parts, are shown in Table B-3. Low sulfur coal is assumed to be available which would eliminate the need for flue gas desulfurization (FGD). However, occasionally local air quality standards are stricter than federal guidelines and FGD systems might be necessary. Due to the cost of an FGD system, an industrial firm faced with the requirement for such a system would most likely reject the idea of conversion[2].

Figure B-1 illustrates an example of a coal or wood handling system. Wood handling systems will be larger due to the low energy density of this high moisture fuel. The number of required fuel handling systems, as well as ash handling and PCSs, summarized in Table B-4 for wood conversions and Table B-3 for coal conversions, represent theoretical maximums. Most industrial firms operate two or more boilers which could be served by solitary common fuel and ash handling, and particulate control systems. However, for the sake of determining potential constraints in direct coal- and wood-firing, the largest possible quantities have been identified.

The time required to engineer and construct a coal- or wood-fired steam generating system, fuel handling facilities and a particulate control system is shown in Figure B-2. The estimated 30 month schedule includes 12 months each for the boiler and fuel handling system procurement. The PCS is expected to be received 13 months after being ordered. Permitting is assumed to begin as engineering begins for reasons outlined in Appendix A.

4. IDENTIFICATION OF POTENTIAL CONSTRAINTS

As shown in Table B-1, the maximum penetrations of direct coal- and wood-fired boilers are expected to be 50 and 41 percent, respectively. These figures represent the individual penetrations of each fuel taken alone. The total combined penetration of both wood and coal is not expected to exceed 50 percent since the two fuels will compete with one another in the event of an oil disruption.

a. Resource Availability

Projected consumption of coal based on maximum penetration is shown in Table B-5. As was the case with CWM conversions (see Appendix A), Regions 1 and 2 exhibit significant increases over present levels. These increases, although not as large as those associated with CWM, account for 130 and 23 percent growth in coal use in Regions 1 and 2, respectively. Coal reserves and transportation systems appear to be adequate to meet the anticipated increase in coal use (see Appendix A). The nationwide maximum potential coal use from the direct-firing of coal is expected to be less than 3 percent of present consumption. Local delivery of coal might require a minor expansion of the present distribution system in all regions except 1 and 2. These regions will most likely require significant increase in their present systems.

As shown on Table B-2, ample wood resources are available for conversions to wood-firing in all regions except Region 2. The penetration estimate for that Region was adjusted accordingly.

b. Fuel Handling

At most, nearly 1,000 solid fuel handling systems will be necessary. As can be seen from Figure B-1 and Tables B-3 and B-4, the size and complexity of these systems will be minimal. Systems of this size, in addition to serving solid fuel industrial boilers, are utilized by many other segments of the industrial sector. Discussions with a materials handling system supplier revealed that, over a three or four year period, the industry could supply all the necessary facilities[3].

c. Solid Fuel Boilers

The largest historical annual sales figure for 100 to 250 x 10^6 Btu/hr boilers (oil and gas-fired) was 248 units in 1973[4]. However, in this size range most solid fuel boilers are field-erected, as opposed to oil and gas boilers which are manufactured in "packaged" form (i.e., delivered to the site in modules for final erection)[5]. The boiler industry, in the last 15 years has only manufactured 500 non-packaged boilers (100 to 250 x 10^6 Btu/hr)[4], only half the 1,000 units that would be required in three to four years. The year with the single highest sales was 1969, when 57 field erected units were sold[4].

Although, as discussed in Appendix A, the most critical component of a boiler is the steam drum, which does not differ significantly between solid fuel and oil- and gas-fired units, the engineering required for larger solid fuel units is more involved. Whereas the boiler industry's capacity to produce smaller CWM-fired units (50 x 10^6 Btu/hr) could be judged based on all steam drums manufactured, this cannot be done with larger boilers[5].

It is obvious, based on historic data, that there exists a shortfall in the capability of manufacturers to meet maximum anticipated coal- and wood-fired boiler requirements. However, several manufacturers have stated that historic data is based on orders received, rather than on capacity, and that more capacity exists that could be utilized[4,5,6]. Estimates of how many boilers could be produced in three to four years from four suppliers varied from 25 to 380[4,5,6,7]. (The latter figure assumes considerable duplication and minimal engineering, which will not be the case.) Adding together the most optimistic estimates of the major boiler manufacturers reveals a three to four year maximum production of 550 solid fuel boilers. This figure is twice as large as an estimate based on historic figures, but still much smaller than the 1,000 units required.

If the boiler industry is unable to supply all the necessary boilers, some industrial firms could possibly utilize gasifiers. As determined in Phase I, gasifiers were found to have higher capital and operating costs than direct-firing. However, some penetration of gasifiers into the industrial sector could be expected, especially if there is a shortfall of solid fuel

boilers. Discussions with gasifier manufacturers indicates that two units should be operated instead of one for reliability and simpler fabrication[8,9]. This would lead to an approximate requirement of 1,000 gasifiers (8,000 cfm for an average size, 135 x 10^6 Btu/hr, industrial boiler) to fulfill the need of industrial firms that would not receive solid fuel boilers.

Gasifier suppliers felt that producing 1,000 gasifiers over a three to four year period could be easily accomplished by the industry. Although, historically, gasifiers have never been produced in such large quantities, capacities of fabrication shops that manufacture component parts are adequate [8,9].

Particulate control systems, for both boilers and gasifiers, would be required. Since it is assumed that low sulfur coal can be utilized, FGD systems have not been investigated. As shown in Appendix A, the capacity of PCS suppliers has been assumed to be adequate to manufacture 1,000 units over three years.

d. Ash Handling

Compared to present regional disposal of ash (see Appendix A), the increase due to a maximum penetration of coal- or wood-fired boilers into the industrial sector would be smaller than three percent (see Table B-6). On a regional basis, Regions 1 and 2 exhibit significant increases, 136 and 23 percent, respectively. The largest projected amounts of ash are a result of direct coal-firing. Wood has relatively small amounts of ash, usually less than one percent*, which makes its impact on ash disposal much less significant.

5. RATE OF OIL DISPLACEMENT

The rate of oil displacement due to the deployment of coal- and wood-fired boilers and gasifiers in the industrial sector is shown graphically in Figure B-3. The initial displacement after one and one half years is based on the estimated schedule of construction (see Section 4) and historic maximum boiler sales. The curve reflects the aggregate procurement of 550 solid fuel boilers and 434 gasifiers, with respective growth rates of production of approximately 43 and 23 percent. The shaded region at four and one half years reflects the possible variation in displacement due to the respective penetrations of coal- or wood-fired boilers into the industrial sector. The upper limit represents the 50

percent penetration of only coal-fired boilers, whereas the lower limit represents a 41 percent penetration (nationwide average) of wood-fired boilers.

6. REFERENCES

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TABLE B-1

PROJECTED REGIONAL DAILY OIL DISPLACEMENT POTENTIAL FOR DIRECT FIRING OF WOOD OR COAL IN THE INDUSTRIAL SECTOR

Region	Boilers Larger than 50 x 10^4 Btu/hr		Direct Coal-Firing			Direct Wood-Firing		
	Number (a)	Projected Oil Use for 1985 (bbl/day) (b)	Market Penetration (%)	Oil Displaced (bbl/day)	Number of (c) Boilers	Market Penetration (%)	Oil Displaced (bbl/day)	Number of (c) Boilers
1	559	52,000	50	26,000	126	50	26,000	126
2	988	92,000	50	46,000	223	20	18,400	89
3	408	38,000	50	19,000	92	50	19,000	92
4	913	85,000	50	42,500	206	50	42,500	206
5	451	42,000	50	21,000	102	50	21,000	102
6	709	66,000	50	33,000	160	50	33,000	160
7	59	5,500	50	2,750	13	20	1,100	5
8	110	10,250	50	5,125	25	20	2,050	10
9	102	9,500	50	4,750	23	20	1,900	9
10	62	5,750	50	2,875	14	20	1,150	6
TOTAL	4361	406,000	50	203,000	984	41	166,100	805

Notes:

(a) "Population and Characteristics of Industrial Boilers in the US," EPA/600/7-79-178A, 1979.

(b) Bull, I, (OIA). Letter to S.S. Nadgauda (Gibbs & Hill, Inc.), December 17, 1982.

(c) 135 x 10^4 Btu/hr Average boiler size and 35 percent capacity factor.

TABLE B-2

ANNUAL POTENTIAL WOOD ENERGY AND MAXIMUM THEORETICAL DAILY OIL DISPLACEMENT BY FEDERAL REGION

Region	Potential Wood Energy (a) Energy (10^{12} Btu/yr)	Barrel of Oil Equivalent (10^6 bbl/yr)	Potential Oil Displacement (bbl/day) (b)
1	136.4	24.8	56,300
2	71.3	13.0	29,500
3	199.2	36.2	82,200
4	564.8	102.7	233,300
5	176.7	32.1	72,900
6	238.7	43.4	98,600
7	43.5	7.9	17,900
8	113.2	20.6	46,800
9	103.6	18.8	42,700
10	351.8	64.0	145,400
TOTAL	2000.0	363.5	825,600

Notes:

(a) USDA Forest Statistics for Commercial Forest Regions
(b) Lower wood boiler efficiencies (estimated average 68 percent) are reflected

TABLE B-3

EQUIPMENT REQUIRED TO REPLACE OIL-FIRED
INDUSTRIAL BOILERS WITH DIRECT COAL-FIRED UNITS

EQUIPMENT	CAPACITY (a)	QTY.
Coal-Fired Steam Generating System	115,000 lb/hr Steam output	
- Stoker Fired Furnace - Forced Draft Fan, Induced Draft Fan - Spreader Stoker Mechanism - Boiler, Superheater, Reheater, Economizer		984
Ash Handling System (b)	750 lb/hr	984
Coal Handling System	10,800 lbs/hr (130 tons/day)	
- Truck or Train Hopper - Coal Elevator - Coal Silo, Gates, Chutes - Weigh Larry, Stoker Hopper		984
Particulate Control System	35,000 scfm 350 F	984
Annual Coal Requirement (12,500 Btu/lb) Per Boiler	16,500 tons	-

Notes:

(a) Average boiler capacity is 35 percent
(b) Based on 7% Ash Coal

TABLE B-4

EQUIPMENT REQUIRED TO REPLACE OIL-FIRED
INDUSTRIAL BOILERS WITH DIRECT WOOD-FIRED UNITS

EQUIPMENT	CAPACITY (a)	QTY.
Wood-Fired Steam Generating System (b)	115,000 lb/hr Steam output	
- Pile or Semipile - Burning Furnace - Forced Draft and Induced Draft Fans - Inclined, water-Cooled grate - Boiler, Superheater, Reheater, Economizer		805
Ash Handling System (c)	190, lbs/hr	805
Wood Handling System	16.6 tons/hr (400 tons/day)	
- Truck Unloading System - Conveyors and Chutes - Hogger and Classifying Screen (Optional) - Storage Bins and Silos		805
Particulate Control System	35,000 sfcm 300 F	805
Annual Wood Requirement (4900 Btu/lb) (d) Per Boiler	51,000 tons	-

Notes:

(a) Average boiler capacity factor is 35 percent
(b) Boiler efficiency assumed to be 68 percent
(c) Ash 1% by weight (dry basis)
(d) 8750 Btu/lb on a dry basis.

TABLE B-5

PRESENT COAL CONSUMPTION AND DEMONSTRATED RESERVES
COMPARED TO DIRECT COAL-FIRING COAL REQUIREMENTS

	Demonstrated Reserves*			Present Coal Consumption			Direct
	less than 1% Sulfur	Bituminous		All Sectors	Utility Boilers	Industrial Boilers	Coal Firing
Region	(10^4 Tons)	(10^4 Tons)	% of All Reserves	(10^4 TPY)	(10^4 TPY)	(10^4 TPY)	(10^4 TPY)
1	-	-	-	1.6	1.2	0.4	2.1
2	-	-	-	16.2	12.1	4.1	3.7
3	23,685.6	67,548.0	92	131.4	98.0	33.4	1.5
4	7,388.4	28,975.6	98	144.3	107.6	36.7	3.4
5	1,778.3	97,913.9	100	218.0	162.5	55.5	1.7
6	4,591.3	3,748.0	68	37.7	28.1	9.6	2.6
7	1.5	8,214.4	100	42.4	31.6	10.8	0.2
8	150,391.9	21,083.6	10	41.4	30.9	10.5	0.4
9	173.3	325.3	100	18.4	13.7	4.7	0.4
10	12,061.9	952.8	12	5.6	4.2	1.4	0.2
TOTAL	200,072.2	228,761.5	-	656.9	477.3	179.6	16.2

Sources: Statistical Abstract of the U.S. 1983, Section 20, Dec. 1982.
1980 Keystone Coal Industry Manual, McGraw - Hill, NY, NY, 1980.

*Only reserves in measured and indicated categories as defined by the USBM and USGS and represents 100% of coal in place.

TABLE B-6

PRESENT AND PROJECTED REGIONAL ASH HANDLING REQUIREMENTS

Region	Present Ash Handling			Direct Coal-Firing Ash	Direct Wood-Firing Ash
	Utility Boilers (10^4 TPY)	Industrial Boilers (10^4 TPY)	Total (10^4 TPY)	(10^4 TPY)	(10^4 TPY)
1	.08	.03	.11	.15	.03
2	.84	.29	1.13	.26	.03
3	6.86	2.34	9.20	.11	.03
4	7.53	2.57	10.10	.24	.06
5	11.38	3.88	15.26	.12	.03
6	1.97	.67	2.64	.18	.05
7	2.21	.75	2.96	.01	*
8	2.16	.74	2.90	.03	*
9	.96	.33	1.29	.03	*
10	.29	.10	0.39	.01	*
TOTAL	33.41	12.57	45.98	1.13	.23

* less than .005 TPY

Source: Derived from Table B-5

FIGURE B-1
EXAMPLE OF COAL OR WOOD HANDLING EQUIPMENT

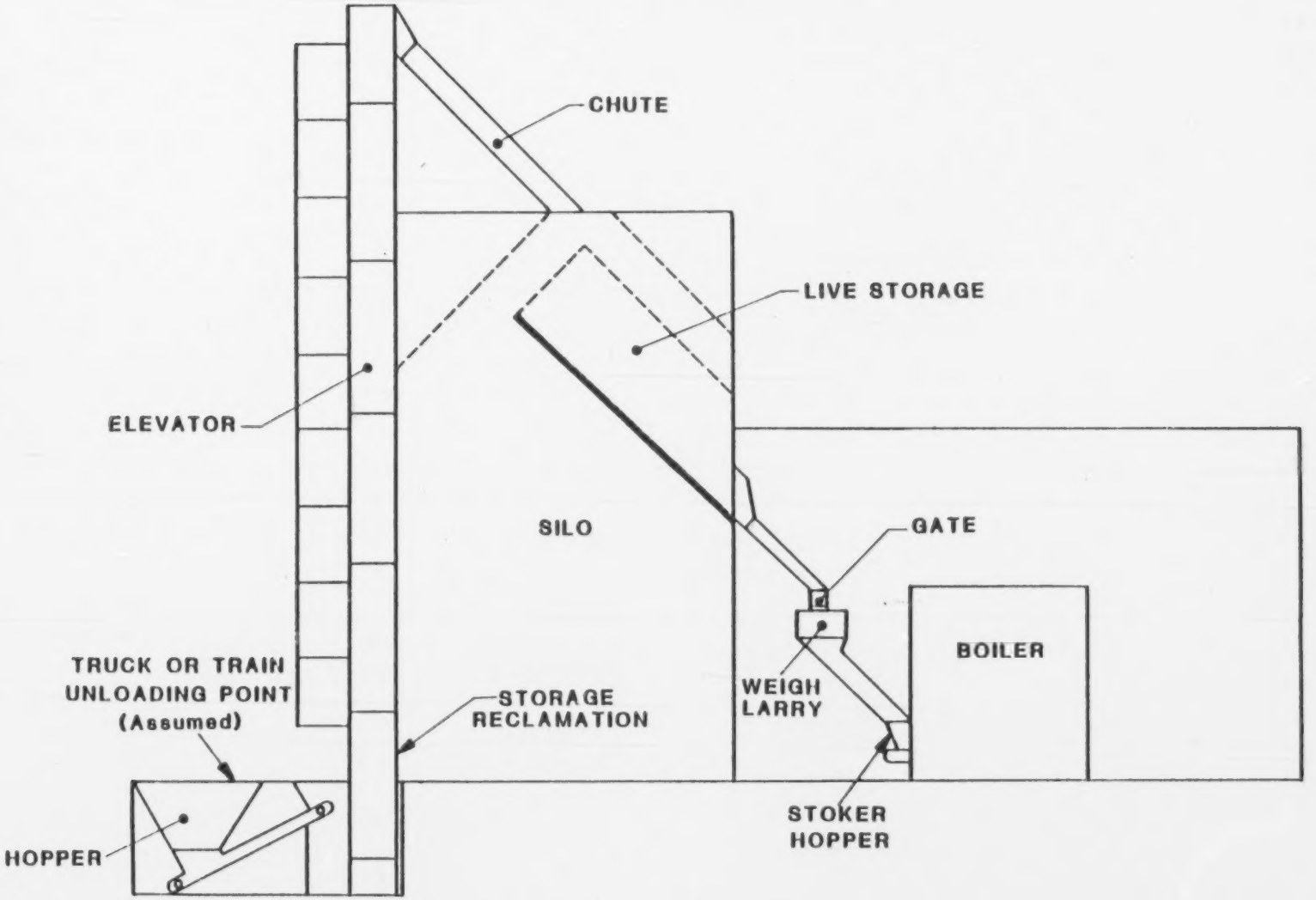
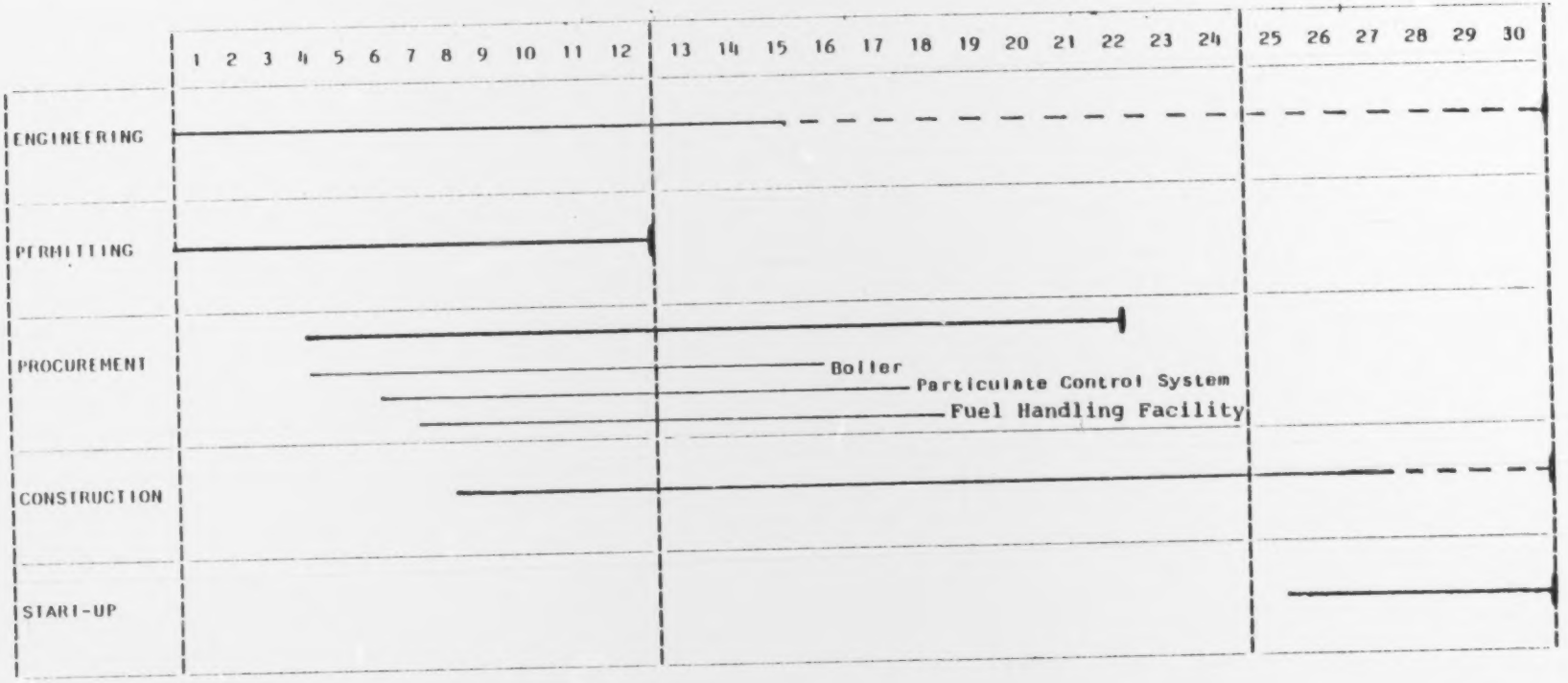


FIGURE B-2

Schedule for Engineering and Construction of a Coal or Wood Firing Steam Generating System
Fuel Handling Facilities and Particulate Control System



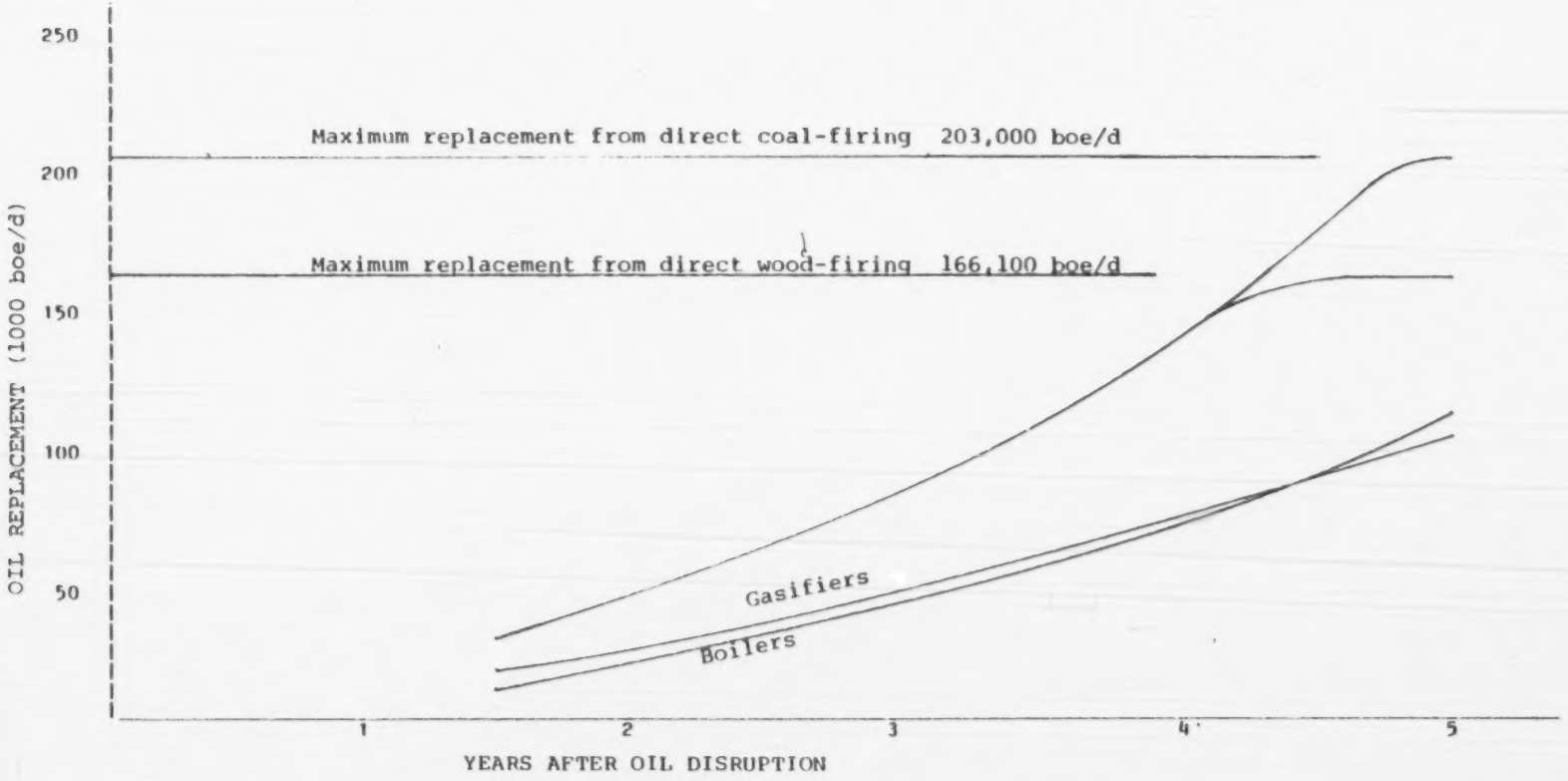


FIGURE B-3

RATE OF OIL DISPLACEMENT; DEPLOYMENT OF WOOD- AND COAL-FIRED BOILERS AND GASIFIERS IN THE INDUSTRIAL SECTOR

C. ENHANCED OIL RECOVERY

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C-2 Schedule for Accelerated EOR CO_2 Flooding Project

C-3 Oil Production Rate for EOR

1. INTRODUCTION

In the Phase I report it was determined that enhanced oil recovery (EOR) is one of the more attractive oil replacement technologies. Compared to the fifteen technologies evaluated, EOR is high in oil replacement potential, moderate in capital cost ($/boe/d), and low in annual cost ($/boe). For planning purposes, a one million bbl/d increase in EOR between 1985 and 1990 was projected in Phase I, equally divided between steam and gas flooding recovery methods.

The constraints associated with implementing an additional one million bbl/d of EOR over a five-year period are examined in this Appendix. The sources of EOR are examined geographically and, according to recovery process, the availability of critical components for rapid deployment of steam and gas flooding projects is assessed. Based on project schedules and critical component availability, the deployment rate of EOR in bbl/d is determined.

2. IMPLEMENTATION OF EOR

Estimates of regional EOR vary but there is agreement that the California and Texas sources offer the greatest potentials. Tosco Corporation estimates that 66 percent of the EOR will be in California and 18 percent in Texas.[1] An earlier OTA estimate places the potentials from both areas as equal, at approximately 28 percent.[2] Both Tosco and OTA agree that Federal Regions 6 and 9 will provide the bulk of the EOR.

Since EOR is a technology that replaces lost imported oil through increased production rather than substitution, regional potential depends on refinery capacity and demand for the type of oil recovered. The proposed 500,000 bbl/d of EOR (heavy oil) via steam flooding will occur predominantly in California (Region 9) where potential market limitations for increased heavy oil utilization exist due to the influx of Alaskan North Slope crude and the lack of heavy oil refining capacity. Transportation of the additional heavy oil produced via EOR to Gulf Coast refineries, will entail shipping through the Panama Canal or through the trans-Panama pipeline currently under construction.[3][4]

The schedular and critical component constraints for the implementation of EOR are addressed herein, while the issues of transportation and the market for heavy oil are excluded from the present analysis. These latter issues are not expected to present bottlenecks since an imported oil cut-off scenario will lead to an excess shipping capacity.

The implementation of an EOR project is time-consuming and under business-as-usual conditions may not yield any additional oil production in a five-year period. Five phases must be completed prior to initiation of fluid injection: screening, planning, permitting, procurement, and construction. After the oil disruption, these phases will still be necessary but sufficient economic incentives will be present to shorten them and where possible permit performance of these activities in parallel.

The screening phase consists of two steps, reservoir evaluation and process selection.[5] The first step consists of a review of the reservoir's producing history and properties with laboratory reservoir fluid and injectant testing. Based on these results and a review of the guidelines for applying the various EOR processes, the EOR process is selected. The total screening phase generally requires three to eight months. If process feasibility is established, the planning phase is initiated.

The planning phase consists of equipment design and selection, additional laboratory tests, reservoir modeling, preparation of manpower and cost estimates, and performance of an economic evaluation.[5] All but the last are performed in parallel and may take up to 12 months to complete. The economic evaluation and project approval are normally completed in 1 to 2 months.

It is anticipated that under crisis conditions with sufficient economic incentives, the screening and planning phases will be shortened from a maximum of 22 months to 8 months. Under business-as-usual conditions, the screening and planning phases for EOR projects have been completed in as little as 8 to 10 months.[5] Although the same resource uncertainties will be present after the oil disruption as before, the substantial economic incentives will permit greater economic risks to be taken and decisions to be made from extrapolation of data from similar reservoirs. The incentives would be strong enough to permit a favorable economic feasibility decision to be reached at an early stage before planning is completed. This would allow preordering of long lead items during the planning stage. Fields that are already in the screening phase at the start of the oil disruption would be the first candidates for the accelerated EOR projects.

Regardless of the project type, steam or CO_2, the time required to complete the screening and planning stages is roughly the same under business-as-usual conditions.[5] It is assumed that the same will prevail after the oil crisis. However, the time required to complete the construction phase of a project varies depending on the process utilized, particularly the securing of injectants. Construction of an EOR project consists of installing equipment, obtaining the injectants, drilling and reworking project wells, and conducting any additional field and

laboratory tests. These steps are performed in parallel and upon their completion project initiation (i.e., fluid injection) begins.

Obtaining regulatory agency approval, particularly for meeting ambient air quality standards, can severely impact project initiation. Emissions from steam generators and from fuel-driven CO_2 injection compressors are the main sources of air pollutants in EOR. Since the environmental permits are required before construction in the field can begin, permit application must be made at the start of reservoir screening for accelerated EOR. Typical state and federal EPA approvals require 12 months.[5] A 10-month span is assumed for the crisis situation.

Figure C-1 illustrates an accelerated schedule for EOR by steam flooding. Critical components are the boiler, particulate control system, coal handling system, and drilling rig availability. The boiler is 50 MMBtu/hr capacity, typical of steam EOR projects. It is assumed that flue gas desulfurization equipment is not required since either low sulfur coals or fluidized bed combustion (FBC) boilers with in-situ sulfur dioxide removal are utilized. FBC boilers are currently incorporated in two commercial EOR projects.[6] It is important to note in Figure C-1 that increased production of oil does not begin until two years after the initiation of steam injection. This is typical of EOR steam flooding projects.[7][8]

An accelerated schedule for EOR by CO_2 flooding is shown in Figure C-2. The schedule is based on above ground CO_2 availability as industrial by-product. The screening, planning, and permitting phases are identical in scope and elapsed time to those for steam flooding EOR. As with steam flooding, critical features of the schedule are the initiation of permitting at the start of screening and the ordering of long lead items during the planning phase. Without these accelerating features there would be no EOR within the 5-year time frame.

The industrial sources of CO_2 include[7]:

- Power plant stack gases
- Vent gases from ammonia and chemical plants
- Flue gases from cement plants
- Vent gases from refinery and hydrogen plants
- Vent gases from natural gas processing plants
- Vent gases from proposed SNG plants.

The schedules for procurement and construction in Figure C-2 are based on CO_2 extracted from power plant stack gas and ammonia plant vent gas.[10-12] These sources bracket low (8 to 12 percent) and high (90 percent minimum) CO_2 streams, respectively. A CO_2 plant based on natural source CO_2 is not included in Figure C-2 because of the excessive time it takes to bring such a plant on line. For example, a natural source project developed by the Shell Oil Company in the Four Corners area (Utah, Colorado, Arizona, New Mexico) for an oil field in West Texas started in 1976 and is not expected to begin CO_2 oil field injection until 1984.[13] This is not to say that natural source CO_2 will not contribute to new EOR after the crisis since this particular Shell project only utilizes one-third of the available CO_2 and the balance two-thirds can be utilized in new EOR projects. However, if a natural source CO_2 project is not well under way at the time of the crisis it is unlikely that any new EOR in the five-year time frame will be realized from the project.

As shown in Figure C-2, critical components for EOR by CO_2 flooding are boilers, pressure vessels, compressors, heat exchangers, and drilling rigs. The boilers are required only for CO_2 recovery from power plant flue gas and are needed to strip the CO_2-laden solvent absorber solution in order to release the CO_2. The flue gas is procured from the power plant at comparatively low cost but the process is energy intensive and including the energy to compress the gas for pipeline delivery can consume over 50 percent of the energy in the recovered oil. A comparable figure for CO_2 from an ammonia plant is 25 percent of the energy in the recovered oil.

3. EVALUATION OF CONSTRAINTS

a. Steam Flooding

Enhanced oil recovery of 500,000 bbl/d of oil via steam flooding requires 750 solid-fuel-fired boilers, each providing 50,000 lb/hr of steam. From Figure C-1, in order to achieve EOR within 5 years, 750 boilers are required over a 28-month period or 320 per year.

The rate of steam injection for a given rock matrix is determined in the screening and planning phases. After an EOR project is designed, i.e., location of wells for each steam generator, the rate of steam injection cannot be arbitrarily increased for the purpose of increasing the rate of EOR.[7] The steam injection rate selected is based on injectivity tests performed at a site. The steam rate at which the pressure produces fracturing in the rock formation is determined. When fracturing occurs an open path exists for the injected fluid and the fluid may not permeate

the rock matrix, i.e., it may bypass the oil. If fracturing occurs on a large scale the project is destroyed. Generally, steam EOR projects operate near the maximum injectivity rate for maximum production. An increase in steam injection rate to increase production is not feasible.

In the 10,000 to 100,000 lb/hr size, boilers are considered "packaged", that is, delivered to the site virtually intact. In this size range more than 800 boilers per year have been sold, including oil and gas as well as solid fuel units (see Appendix A). As discussed in Appendix A, the oil and gas boiler manufacturing capacity in this size range can be credited toward solid fuel boiler manufacturing capacity. Thus, the availability of boilers does not present a constraint.

After the oil disruption, large EOR projects would be planned and oil companies may initially elect to specify larger solid fuel boilers providing steam in excess of 250,000 lb/hr. As discussed in Appendix B, this size boiler is field erected and the manufacturing capability is appreciably less. Delivery time would be longer and, thus, it is expected that multiple boilers of the 50,000 lb/hr size would continue to be the preferred design approach.

Similar to boilers, 750 particulate control systems (PCS's) or 320/per year are required for EOR of 500,000 bbl/d. As discussed in Appendix A, industry could produce 1000 units over 3 years. Thus, PCS's do not present a constraint.

The number of solid fuel handling systems required depends on the arrangement of boilers at EOR sites, that is, whether the boilers are dispersed or at common locations. The theoretical maximum number of fuel handling systems is 750. As discussed in Appendix A, availability of this number of fuel handling systems is not a constraint. Handling systems are a common component of many industrial operations and the capability for manufacturing other types of handling systems can be applied to solid fuel handling systems as well.

A typical 50,000 lb/hr boiler will provide steam for nine injection wells and one production well.[8] Using a conservative assumption of seven days to drill each well[7] and a 22-month period for drilling wells (from Figure C-1), the number of rigs required is approximately 80 per year [=(10x750x7)/(22/12)(365)]. Doubling this number to account for a large demand at the beginning of the crisis and for time necessary to set up and install rigs at various sites is considered prudent for planning purposes. Based on 2700 idle rigs in March 1983,[14] the 160 rigs for steam EOR does not present a constraint.

In addition to the potential hardware constraints discussed above, there are the potential resource constraints of coal availability and ash disposal sites. Steam EOR of 500,000 bbl/d requires 15.8 million tons per year of low sulfur coal. As shown in Appendix A, Table A-10, on a national basis this represents an increase of only 2.5 percent and reserves are abundant. However, in Region 9, where almost all of the steam EOR is anticipated, the increase in coal use is 85 percent.

In Phase I of this report it was determined that the transportation of coal on a national basis in the event of the oil crisis was adequate to handle anticipated increased shipments. Some minor regional transportation bottlenecks are possible in Region 9, but it is not considered a long term constraint to the increased use of coal.

With regard to ash disposal, 150 boilers (50,000 lb/hr) will generate 1.11 million tons per year of ash. As shown in Table A-11 (Appendix A), on a national basis this is a small increase but in terms of Region 9 it represents an increase of 85 percent. It is more of a problem than coal supply because of the environmental considerations.

b. CO_2 Flooding

The production of oil via CO_2 EOR depends on the ability to deliver sufficient CO_2. Current production is 22,000 bbl/d[15] requiring approximately 220 MMscf/d of CO_2. Ninety-five percent of CO_2 EOR occurs in West Texas. It is assumed that after the oil disruption, for a period of 5 years 85 percent of the CO_2 EOR will occur in West Texas because of historical success in this area and because of the West Texas carbonate reservoirs which are most compatible with CO_2 EOR.[9] The balance 15 percent is assumed to be in Louisiana.

The CO_2 available for EOR in West Texas is shown in Table C-1. Approximately one-third of the CO_2 is available from the natural source plant in the Four Corners Area discussed earlier. The Shell Oil Company has not currently designated the available 667 MMscf/d of CO_2 to any EOR projects.[16] The major 500-mile pipeline will be in place by 1983 and the smaller, less distant pipelines to other oil fields can be constructed very rapidly.[18] Thus, there appears to be no constraint to use of this natural source of CO_2 for EOR within the five-year period.

The balance of the CO_2 is available from industrial by-product sources. Constraints are evaluated below by examining the critical components for CO_2 plants based on power plant flue gas and ammonia plant vent gas.

A CO_2 plant based on power plant flue gas has recently been completed in Lubbock, Texas, utilizing two power plants totaling 100 MW.[10] [12] [17] [18] The CO_2 process plant takes flue gas from each power plant in separate trains and provides 20 MMscf/d of CO_2. This size and arrangement is typical of others that can be constructed in West Texas.[10]

Based on the Lubbock, Texas, plant recovery of 995 MMscf/d of CO_2 from power plants requires one hundred 100,000 lb/hr packaged boilers. After the oil disruption it is assumed that these boilers will be solid fuel-fired. Based on the constraint evaluation performed for the 750 packaged boilers for steam EOR, the requirement for 100 additional boilers and the associated PCS's and solids handling equipment does not present a constraint.

CO_2 plants each require an absorber, regenerator, accumulator, and other major pressure vessels and heat exchangers totaling 400 to 500 over a 2-year period.[12] [18] Most of the heat exchangers are shell-and-tube type.[12] The number of vessel and shell-and-tube heat exchanger manufacturers is approximately 100 in each category [19] and a constraint based on manufacturing capability is not anticipated.

The purified CO_2 product is compressed to 2000 psi for pipeline delivery and well injection. Each 20 MMscf/d plant has three compressors, each 2250 hp (3- or 4-stage type), bringing the total required to 150 over a 2-year period.[10] [20] In 1980, a total of 5512 gas compressors were shipped from manufacturers in the U.S.[21] A constraint due to compressor availability is not anticipated. Thus, it appears that there are no process plant equipment constraints to building flue gas CO_2 plants providing 995 MMscf/d over a 2-year period.

The balance of the available CO_2 in West Texas, amounting to 344 MMscf/d, will come from cement plants and process plants. A CO_2 plant based on ammonia vent gas is assumed to be representative of these by-product sources. CO_2 plants based on ammonia plants are typically 3 to 10 MMscf/d size in CO_2 output. For maximum constraint in terms of amount of equipment required the constraint evaluation is based on the small size plant.

A 3-MMscf/d plant requires the following major equipment that may present a constraint:[11]

- CO_2 liquefaction compressor (650 hp)
- Refrigerant compressor (383 hp)
- CO_2 pipeline compressor (900 hp)

- Large vessels and heat exchangers, totaling four to five.

For production of 344 MMscf/d of CO_2, 115 compressors and 400 to 600 total vessels and heat exchangers are required over a 2-year period. Combining these totals with flue gas CO_2 plant needs yield 265 gas compressors and a maximum of 1100 vessels and heat exchangers. As discussed earlier, based on historical production and numbers of manufacturers, these quantities do not present a constraint.

The number of wells required per CO_2 EOR production rate is not as consistent as the number required per production rate for steam EOR. Review of the number of injection and production wells in current CO_2 EOR projects[15] and in a large project planned by the Shell Oil Company[13] reveals an average of 18 injection wells and 55 total wells per 1000 bbl/day of EOR production. Not all production wells require redrilling and 30 total wells per 1000 bbl/day of EOR is assumed. Total CO_2 EOR production is expected to reach 275,000 bbl/day in the five-year period (see Section 4). Using a conservative assumption of 10 days to drill each well and an 18-month period for drilling wells (Figure C-2), the number of rigs required is approximately 150 per year [=(275,000)(30/1000)(10)/(18/12)(365)]. Similar to steam EOR, this number is doubled for set-up time and moving of rigs. Based on 2700 idle rigs in March 1983,[14] the total of 460 rigs for steam and CO_2 EOR does not present a constraint.

4. OIL PRODUCTION RATE

The oil production rate attributed to EOR is summarized in Figure C-3. Based on Figure C-1, EOR from steam flooding begins 3.7 years after the oil disruption and reaches the 500,000 bbl/d potential in 5 years. Despite the anticipated large activity in steam EOR at the beginning of the crisis, a large incremental increase at the 3.7-year point is not anticipated because it is expected that the number of wells showing enhanced production will steadily, but not incrementally, increase two years after steam injection begins.

Based on Figure C-2, EOR from CO_2 flooding begins four years after the oil disruption.

The production at the end of five years is constrained by the availability of CO_2 in West Texas. Based on 85 percent of the CO_2 EOR in West Texas and 10,000 scf of CO_2 required per barrel of oil recovered, the CO_2 required is 4,250 MMscf/d. Since only 2006 MMscf/d is available, the EOR is limited to 200,000 bbl/d [=(.85)(500,000)(2006/4250)] in West Texas. Sufficient quantities of CO_2 are available in Louisiana to support the balance 75,000 bbl/d of EOR.[9]

It could be argued that Louisiana could provide more than 75,000 bbl/d of EOR or that other regions with available CO_2 and compatible oil reservoirs would provide EOR production. This is not expected, however, since CO_2 EOR production in these areas does not have the historical production rates of West Texas. A one-year delay in implementing EOR projects effectively eliminates any EOR in five years and a delay of this type seems inevitable since activity will be concentrated in the area with the most promising production, i.e., West Texas. Compared to West Texas in the case of Louisiana, CO_2 EOR has had less success in this area and hence only limited production can be anticipated over a five-year period.

The CO_2 EOR production reaches 275,000 bbl/d in 5 years. A rate of increase of oil production similar to steam EOR is anticipated as shown in Figure C-3.

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TABLE C-1

SOURCES OF CARBON DIOXIDE IN WEST TEXAS

Source	Total CO_2 (MMscf/d)	Penetration	CO_2 for EOR (MMscf/d)
Power Plant	1421.9	70%	995
Cement Plant	253.0	70%	177
Process Plant	237.9	70%	167
Natural	667*	100%	667
			2006

* Excess capacity from the Shell Oil Company plant in the Four Corners Area. Pipeline to West Texas to be completed in August 1983.

Adapted from Ref. (9)&(16)

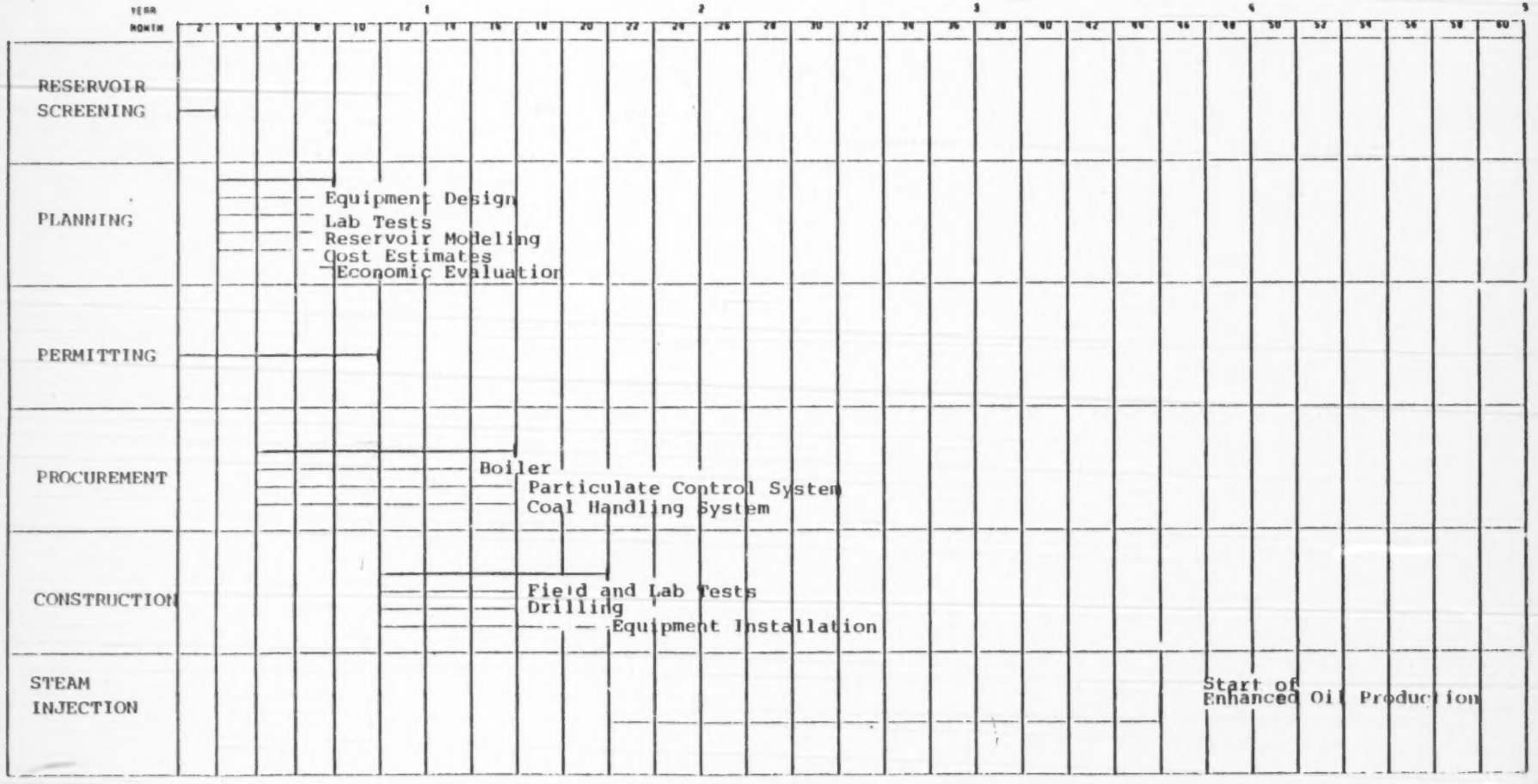

FIGURE C-1

SCHEDULE FOR ACCELERATED EOR STEAM FLOODING PROJECT

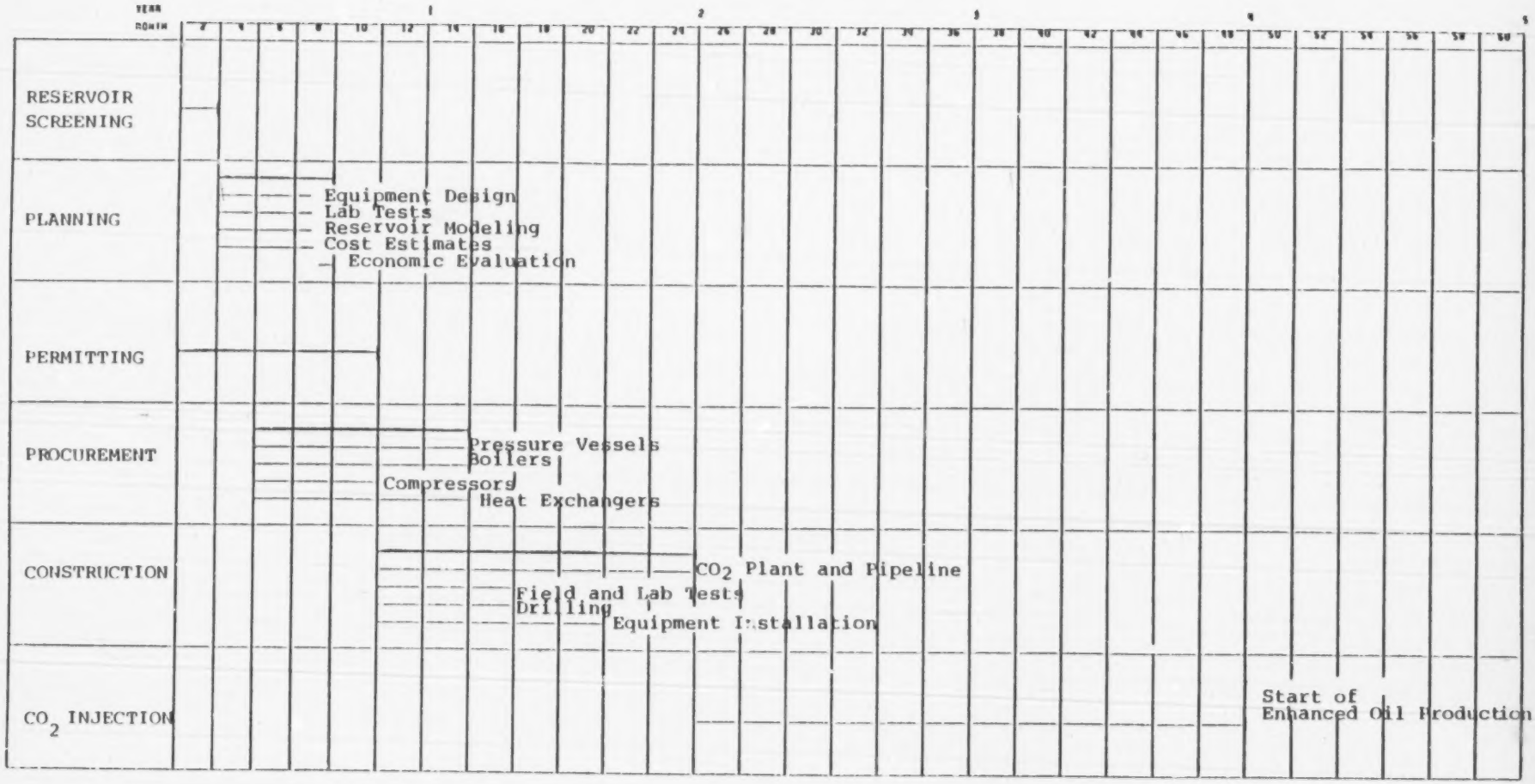

FIGURE C-2

SCHEDULE FOR ACCELERATED EOR CO_2 FLOODING PROJECT

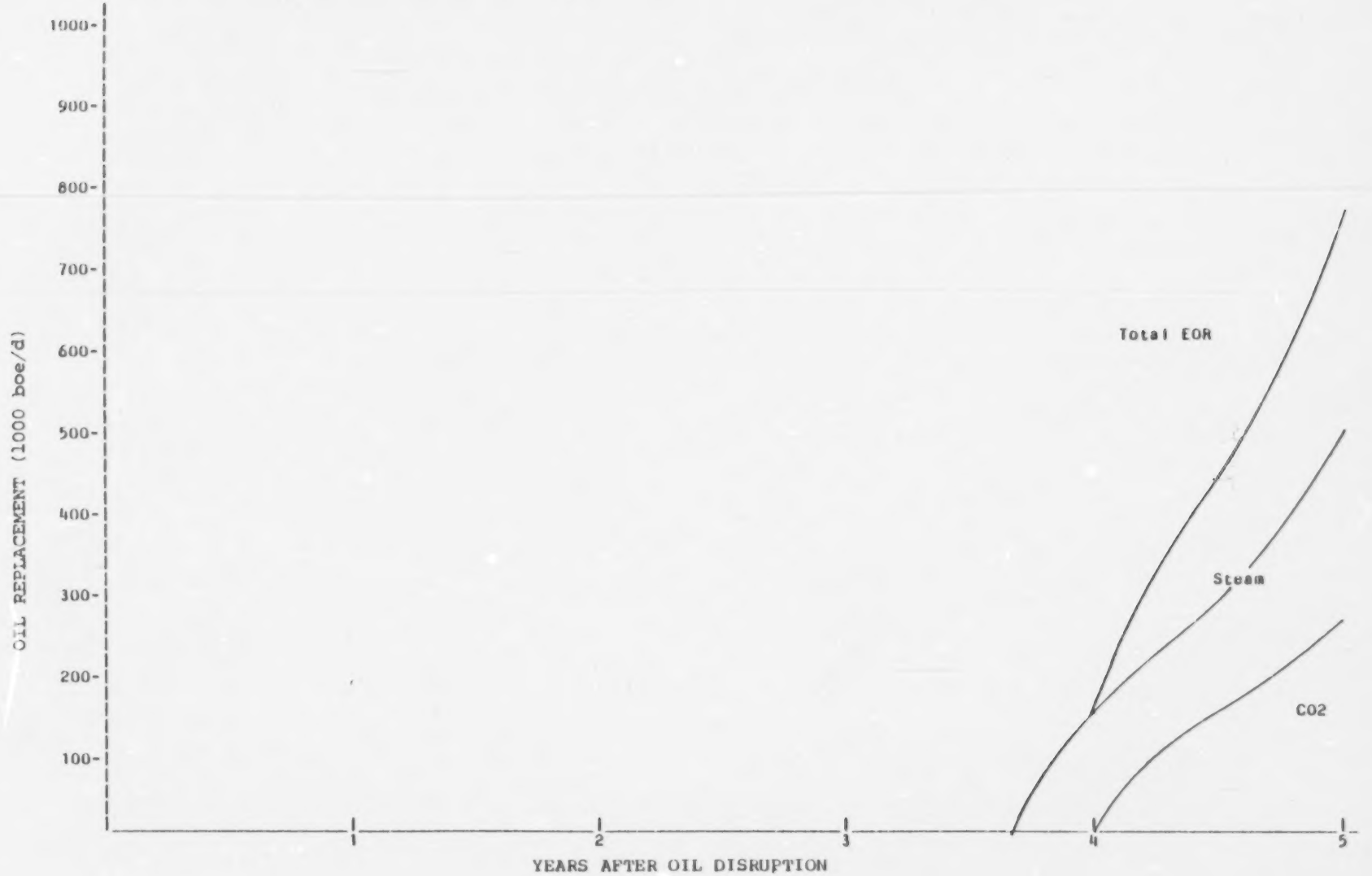

FIGURE C-3

OIL PRODUCTION RATE FOR EOR

D. NATURAL GAS

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1. INTRODUCTION

As determined in Phase I of this study, oil to natural gas conversions in the residential/commercial, industrial, utility, and transportation sectors are cost effective in minimizing the adverse impacts of a short fall in U.S. oil imports. For these conversions to occur, an increase in the supply of natural gas will be required. Determination of the precise sources and amounts of increased supplies is beyond the scope of this study. However, a survey of eleven recent supply projections made by interested associations and Federal agencies (see Section 3) revealed several common findings which indicate sources of supply likely to be significant. But due to the lack of concensus among these projections with respect to specific volumes of supply, it is difficult to arrive at an accurate figure for a possible increase. The imminent deregulation of the gas industry also contributes a plethora of uncertainties, further hampering the ability to make any rational estimates.

In order to evaluate potential constraints of increased gas use and supply, some estimate of increased gas supply must be made. For the purposes of this study, a figure of two trillion cubic feet (TCF) per year is used as a basis for determining constraints. This figure represents an oil displacement potential of 1,000,000 bbl/day assumed to be attainable in at least five years after an imported oil cut-off. Sources most likely to supply this gas as well as potential transportation and storage constraints are investigated as part of this Appendix. Constraints in utilizing a 2 TCF per year increase are also determined for the residential/commercial, industrial and utility sectors as well. (Appendix E addresses the problems associated with conversions to compressed natural gas in the transportation sector.)

The degree to which conversions in these sectors will occur is based on the estimated increase. Although conversions to compressed natural gas vehicles could consume a maximum of 0.2 TCF/yr (see Appendix E), which would result in 1.8 TCF/yr available to non-transportation sector conversions, it is assumed that the entire 2 TCF/yr will be consumed by these sectors. This methodology will identify potential constraints that might otherwise not be as evident if a smaller amount of gas were assumed to be available.

The estimate of a 2 TCF/yr increase in natural gas supply was selected as a plausible figure in light of various published projections (see Section 3). It is not the intent of this report to provide an in-depth study of sources of natural gas and the above estimate should not be construed as the result of one. Albeit slightly arbitrary, an increase of 2 TCF is well within the range of estimates made by informed sources; for example, projections of gas supply in 1990 vary by as much as 9.0 TCF/yr which illustrates the degree of accuracy inherent in any estimate. In addition, the American Gas Association believes that there is currently an excess gas production capacity of 2.5 to 2.7 TCF/yr.[7] They also state that many analysts expect this situation to persist during the 1980's.

2. PROJECTED OIL USE AND CONVERSION TO NATURAL GAS

In order to make an estimate of conversions from oil to natural gas (NG) in the event of an imported oil cut-off, two methodologies are employed to arrive at penetration estimates. The first is to select a uniform, nationwide percentage of the oil consuming segment that, based on the profile of oil users, could most likely be converted to NG. This penetration estimate is applied to each region and the resulting increased NG consumption based on this percentage is compared to present consumption figures to identify regions where increases are significant.

The second method of determining the penetration of NG conversions is based on present NG consumption instead of projected oil use. The regional increases in NG consumption, based on a uniform nationwide penetration estimate, are kept as small as possible for each region. This in turn indicates a required regional specific penetration in order to arrive at the specified increase in consumption. The resultant penetration requirements are compared to the estimate made initially to identify regions where exceedingly large penetrations will be necessary.

It is expected that, on a regional basis, the number of conversions to NG and increases in present NG consumption will be at levels between the maximum limits arrived at by identifying the penetration of NG conversions. But these limits define the constraints that will dictate the amounts of oil that can be displaced by NG. This will be shown in the following sections that investigate NG conversion for each sector.

a. Residential/Commercial Sector

Projections of heat and hot water oil use for 1985 have been prepared by OTA.[1] These figures have been converted to units of energy (Btu) and are shown on Table D-1. Since data provided by OTA does not specifically identify oil use by sector, it is assumed that all of the residential sector and most of the commercial sector consumes distillate and kerosene for heating and hot water. By examining the oil use projections it is apparent that Regions 1 through 5 are expected to consume most of the Residential/Commercial oil in 1985. These regions will offer the largest potential to reduce oil consumption by conversion to NG.

The distribution of present residential and commercial gas use is much more regionally uniform than projected oil use.[2] Table D-1 also depicts the contribution of each fuel to the sector as a whole. The consumption of NG is more than four times larger than that of expected oil use. This indicates that if all future oil use were to be replaced by NG, the increase in NG sales to the residential/commercial sector would be less than 25 percent. Gas sales to this sector have exhibited increases larger than 25 percent over the periods 1955-1960 (45 percent), 1960-1965 (30 percent) and 1965-1970 (30 percent).[3]

Although, based on historical performance it appears that the gas industry could penetrate 100 percent into the oil use market, this is most likely not possible. The absolute number of new customers required for conversion would be much greater today than during the 1970's due to a significantly larger customer base. The inability of the industry to achieve any significant increase over the last 10 years in the residential/commercial sector[3] in some areas also indicates that, under the prevailing economic conditions, market saturation may have been reached.

Based on the distribution of oil burning households in the U.S., 50 percent is assumed to be the maximum penetration of NG conversions into the oil use market. Housing data indicates that 13.4×10^6 households in the U.S., burn oil for heat.[4] About one third (36 percent) of these homes are in rural areas[4] which could not be economically converted (the gas use would not justify the cost of distribution). The remainder, 8.6×10^6 households are located in urban areas. If we assume 80 percent of these households were to heat with NG, then

6.8×10^6 households would be converted. This figure represents approximately half of the 13.4×10^6 households burning oil nationally, or a 50 percent penetration.

Table D-2 illustrates the increase in gas sales, by region, based on a uniform 50 percent penetration of residential and commercial oil to gas conversions. The nationwide increase, 883.1×10^{12} Btu/yr (or 0.88 quads), as estimated would represent an increase over present gas consumption in the residential/commercial sector of 12 percent. However, regionally, the Northeast exhibits much larger increases. Regions 1, 2 and 3, based on 50 percent of oil heated households converting to gas, would need to increase gas sales by 72, 27 and 52 percent, respectively. The constraints in achieving such increases, especially in Regions 1 and 3 are explored in Section 4.

If a significant increase in gas use is assumed to limit the number of conversions in any one region, then Regions in the Northeast may not achieve 50 percent penetration. However, nationwide the same increase in gas use, 883.1×10^{12} Btu/yr or 12 percent, could be achieved if Regions with large gas consumption and fewer oil heating households reached maximum possible penetration. Table D-2 shows the minimum regional increases in gas use if penetrations in Regions 4 through 9 are at a maximum (i.e, all urban households). These Regions, even at 64 percent penetration, exhibit small increases in present gas consumption, which would indicate that a maximum penetration could be possible. Regions 1, 2 and 3, under this scenario would have to increase their gas use by less than 25 percent, a more reasonable figure compared to increases associated with a 50 percent penetration.

Based on the average gas consumption of a household heating with gas in each region, the estimated increase in gas use (see Table D-2), and the national number of oil heating households expected to convert to gas, the number of required conversions in each region was determined. Table D-3 presents these figures in comparison to the present profile of residential/commercial gas customers. As shown, over 5×10^6 of the 46.8×10^6 gas customers do not heat with gas (gas is used for cooking and clothes drying). Conversations with gas utilities indicate that half of non-heating gas customers can be supplied immediately with sufficient gas to heat their homes.[5,6] The total

number of anticipated conversions less 50 percent of non-heating customers reveals the number of customers that will require new distribution lines to their homes (see Table D-3). This figure, when compared to the present customer base shows that for Regions 3, 4, 6 and 10 the increase in new customers would be greater than ten percent. Potential constraints in performing the necessary conversions in these regions are investigated in Section 4 of this appendix.

b. Industrial Sector

Present NG sales to the Industrial sector as well as projected oil use are listed, by region, on Table D-4. In order to determine the segment of the industrial sector likely to convert to NG, the regional maximum amount of oil potentially displaced by either CWM, coal or wood, as determined in Appendices A and B, is accounted for. Industrial boilers most likely to convert to NG will not include those units that could convert to burn a solid fuel (CWM included). Wood, coal and CWM will be less expensive fuels in the time of a crisis and boilers large enough to economically justify the higher initial cost of converting will choose these fuels over NG.

Conversions to wood, coal and CWM are all expected to occur in the same segment of the industrial sector (oil-fired boilers larger than 50 x 10^6 Btu/hr). Therefore, the largest regional oil displacement potential of any one fuel, rather than the total of all three, has been subtracted from the total projected oil use of the industrial sector to arrive at the oil use segment most likely to convert to NG (see Table D-4). This oil use profile is used as a basis to determine the oil displacement potential of additional NG use.

Based on a total estimated increase in NG supply of 2 TCF/yr (see Section 1) and an anticipated increase in residential/commercial NG use of 0.88 TCF/yr, the increase in NG use in the industrial (and utility) sector has been determined. It is assumed, for the purposes of this study, that conversions to NG in the industrial and utility sectors will be in the same proportion. The result is a national average penetration of conversions of 48 percent for both sectors. Table D-5 lists the regional increases in NG use in the industrial sector. Employing the same methods developed for the residential/commercial sector, regional increases are shown for both uniform regional penetration and varying penetrations that result in the

minimum possible increases. The latter scenario results in the same national increase in NG use, 911.3 x 10^{12} Btu/yr, but much less severe conversion requirements in the Northeast (see Table D-5). Although maximum penetrations will be necessary in other regions, these regions will only experience small percent increases in NG use compared to the present.

c. Utility Sector

The determination of increased NG consumption resulting from conversions of utility boilers is revealed in Tables D-6 and D-7. The methodology of arriving at regional increases in NG use is identical to that of the industrial sector. However, projected utility oil use has been adjusted for possible conversions to CWM, not coal and wood.* The projected utility oil use of likely candidates for conversion to NG (see Table D-6) represents the oil use of Type 2 (see Table A-2) boilers and distillate-fired peaking units. Conversion of these electric generators to CWM is considered highly improbable (see Appendix A).

3. PRESENT AND PROJECTED NATURAL GAS SUPPLY

a. Sources of Natural Gas

The supply of natural gas can be classified into four major types: conventional, non-conventional, imports, and substitute natural gas. Conventional gas is gas produced by customary technology from reservoirs having permeability greater than 1 millidarcy. Presently all conventional gas is produced in the contiguous 48 states (referred to as the "lower 48" in the industry) and represented 94 percent of marketed production in 1981.** (See Table D-8.) Although no Alaskan gas was marketed in the lower 48 states in 1981, conventional gas supply projections usually identify some future marketing of gas from Alaskan sources. Two modes of delivery to U.S. markets are being discussed. One involves the construction of a pipeline to deliver gas from the Alaskan North Slope field to the Northwest and the other is construction of liquefaction and regasification

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* Utility firing of wood is expected to be minimal and OTA projected oil use takes into account coal. conversions.

** Latest available figures

facilities to deliver liquefied natural gas (LNG) from South Alaskan sources to the West Coast.

Non-conventional describes all sources that require more than customary production technology. This is due to either the low permeability of the source, as with Devonian shale, "tight sand" formation reservoirs, and coal seams, or the entrainment of the gas in another media (geopressured brines). In 1981, less than one percent of marketed gas was non-conventional. The entire 0.2 TCF/yr was produced from tight sands. Massive hydraulic fracturing is required to induce wells in these formations to flow at adequate rates. The significantly higher cost of performing this fracturing, as well as the still developing technical expertise required, has to date, kept the production of this, and other non-conventional sources, from becoming meaningful.

Foreign imports of natural gas represented 5 percent of 1981 totals, most of it purchased from Canada. Mexican and Algerian (in the form of LNG) imports were each ten percent of total imports (see Table D-8). Some future Indonesian LNG imports are expected and will make use of the same facilities planned for South Alaskan LNG, when and if those facilities are completed.

Substitute natural gas (SNG) is presently derived from either propane, butane or naptha. In 1981, 0.1 TCF of SNG was marketed in the U.S., less than one half of one percent of all marketed gas. Development is underway of processes for production of SNG from coal, peat and solid wastes. For the purposes of this study, and to be consistent with industry nomenclature, coal gasification is considered an SNG but peat and solid waste derived gas is considered non-conventional derived from biomass.

b. Estimates of Future Production

Employing the categories of sources described in the previous section, a variety of projections of natural gas supply for 1985 have been summarized on Table D-9. The supply estimates are based on normal conditions and do not reflect any of the affects of deregulation. It is immediately apparent, after examining the projections, that there is little agreement among the interested parties making forecasts. Total supply varies by as much as 4.3×10^{15} Btu/yr. (A recent paper prepared by the American Gas Association[7] reports a 2.6×10^{15} Btu/yr difference between projections. However, forecasts made by the National Research Council

were not included and individual sources were not shown.)

The only identifiable trend is a decrease in conventional production. Forecasts of this decrease differ by 3.5×10^{15} Btu/yr. Projections of every other source are both greater and less than actual figures for 1981.

Projections of gas supply available in 1990 (see Table D-10) represent the results of an imagined crisis, "national commitment" or large price increases. As was the case with 1985 projections, disparity is the rule. However, each projection, compared to forecasts of 1985, indicates that significant increases in gas production are possible over a five year period. These increases range from 2.1 to 9.6×10^{15} Btu/yr. There is no real agreement on the sources of this increase. Non-conventional sources are expected to increase from present levels but, according to forecasts this could be either 1.6 or 3.6×10^{15} Btu/yr. Some projections allude to significant reliance on foreign sources while another anticipates less imports than at present.

With respect to these projections, for 1985 and 1990, an increase in annual supply of 2×10^{15} Btu developed over five years, used as an estimate in Section 2, may be possible. For the purposes of determining the impact on pipelines and storage facilities, it is assumed that half will be supplied from conventional sources[8,9] and half from non-conventional and substitute sources.

4. IDENTIFICATION OF POTENTIAL CONSTRAINTS

a. Supply

As discussed in Section 3, projections of gas supply vary so widely that precise evaluations of sources with respect to expected production rates would not be meaningful. However, irrespective of volumes of supply, potential constraints associated with several sources are evident.

Alaskan gas - Regulatory delays and increased costs have cast doubt on the timely completion of the Alaskan pipeline or LNG facilities. The supply of gas from Alaska, in considerable volumes, is expected in the late 1980's or early 1990's.[10,11] It would be imprudent to expect completion of such large projects to be on schedule. Likewise, the supply of gas from Alaska

should not be counted on to be significant or even extant from 1985 to 1990.

Tight sands - Although gas from tight sands, in particular, blanket formations, has been and will continue to be produced, the technology and expertise to make tight sands a significant source are lacking. Limited ability to accurately define and effectively fracture tight sand formations, especially lenticular sands, has severely restricted production rates. The high cost of these inefficiencies has contributed a slowdown on research and development. When and if gas prices increase to levels high enough to stimulate active interest in this resource, pipelines to transport an increased supply might prove inadequate. Due to present low production rates of gas near major reservoirs of tight sands gas, namely the Rocky Mountain and Northern Great Plains regions, existing pipelines may not be capable of handling significantly greater volumes.[12]

Devonian Shale - All of the constraints identified for tight sands exist for Devonian shale. Foremost is the lack of developed exploration and fracturing knowledge. Gas supplies from Devonian shale formations will most likely occur well after tight sands formations have been successfully exploited.[12]

Coal Seams - A variety of legal, environmental and technical constraints exist with respect to this source of natural gas. The ownership issue of coal seams must be resolved before any significant development of this source can occur. Environmentally, the availability of water required for fracturing and its disposal are major impediments. Finally, the uncertainties associated with production characteristics and damage to coal seams would indicate that this source will not be a significant contributor to national gas supplies.

Geopressured Brines - The identification of large enough reservoirs that can be continuously depleted is the first hurdle to be overcome in developing this source. Once this has been accomplished, the disposal of the resulting brine presents another significant obstacle. Even the most optimistic projections indicate that geopressured brines will not be the source of any sizeable quantities of gas until the 21st century.

Imports - It is beyond the scope of this study to anticipate the international effects of an oil disruption. Some foreign gas will most likely be available, especially from Canada and Mexico, however determining the quantity of that supply is beyond the G&H study scope.

b. Production, Transportation and Storage

Production - Drilling Rigs - Based on the average net well head production of a non-associated gas well, 121.5 x 10^6 cubic feet per year,[13] and the anticipated supply of gas from new wells (see Section 3), 8230 producing wells will be necessary to meet the total increase in estimated output. In 1980, the sucess rate of drilling for gas was 30 percent[14] which indicates that the necessary number of producing wells would require more than 27,000 attempted wells. Considering average figures for well completions per rig, about 21 per year, [13,15] nearly 1,300 drilling rigs would be required over a 5 year period. If one year is allocated for exploration, then approximately 300 rigs would be required to drill continuously for four years.

Presently, there are 1800 active drilling rigs in the U.S.[16] This figure is down from a high of over 4500 at the end of 1981[15] which would indicate that a surplus of 2700 rigs exists. Although this would appear to be a large enough surplus to satisfy gas drilling requirements in the event of an oil cut-off, gas drillers would be competing with oil drillers. Therefore, drilling rigs might be available at a slower rate which would delay anticipated production of gas.

Transportation - An additional annual gas use of 2 TCF/yr will necessarily have an impact on transportation and storage facilities. Table D-11 summarizes, regionally, the increases in gas use resulting from conversions in all sectors. Regions 1, 2 and 3 exhibit the largest increases compared to present sales figures. It has been established that major pipelines have the capacity to deliver the anticipated increase to these regions. The excess capacity of four major pipelines to the Northeast was 0.86 TCF in 1981 (see Table D-12). If gas deliveries to these regions remain constant through 1985, then the anticipated increase in use of 0.61 TCF per year should pose no problems to these pipelines.

However, gas deliveries to Region 1 are solely dependent on two pipelines, both of which are operating at close

to their maximum capacity. A spokesperson for the Algonquin Gas Transmission Co., which delivers the majority of NG to Region 1, stated that the physical enlargement of their system to accommodate a significant increase would take from one to two years. Additional lead time to obtain all of the necessary government approvals and rights-of-way would be required but is difficult to predict.[21]

Regions 9 and 10 were also studied for possible pipeline constraints due to the limited number of companies serving those regions. The four pipeline firms that serve the Northwest are listed in Table D-12 along with their aggregate excess capacity. The projected increase in gas sales to Regions 9 and 10 of 0.13 TCF (see Table D-11) is much less than the indicated excess capacity of 0.58 TCF.

Storage - Storage of natural gas is required primarily for residential and commercial customers to meet peak demands during the heating season. Table D-13 identifies U.S. gas storage characteristics at the end of 1981. The term "working gas" refers to the total available volume of gas readily available for withdrawal. The storage volume necessary to meet the expected increase in gas use is less than five percent of this figure and is less than one quarter of the available unused storage capacity at the end of 1981. It should also be noted that regionally there appears to be no problem in storing additional gas. Regions 2 and 3 (which can be considered one region with respect to storage) had unused capacity of 95.2×10^{12} Btu, more than twice the anticipated increase in required storage.

c. Implementation of Conversions

Residential/Commercial Sector - As determined in Section 2, a total of almost 4.4×10^6 new residential/commercial customers must be converted to gas heat in order to displace the identified quantities of oil (see Table D-3). Comparing this number of required new customers to the largest nationwide historical five year increase, 5.3×10^6 (see Table D-14), indicates that 4.4×10^6 conversions could be performed by the gas utility industry. However, a region by region comparison reveals that some areas of the country will have to add more customers than they have done in the past. These regions might encounter initial shortages in available manpower to install distribution lines, although these personnel could be adequately trained in as little as two months.[17]

Industrial Sector - Based on the average yearly consumption of industrial customers, 41.9×10^9 Btu/customer[18], and the estimated increase in gas use from conversions (see Table D-5), approximately 21,770 new customers will have to be converted to gas. Presently, 187,800 industrial firms consume gas.[19] This figure is much less than the 209,100 companies serviced in 1973. It is assumed that most of those firms that have stopped using gas over the last ten years have retained the ability to switch back.[5,6] This would indicate that the anticipated increase in gas use would be fairly simple to achieve. Even if some new distribution lines are required, compared to figures for the residential/commercial sector, constraints would be minimal.

Utility Sector - Gas consumed for electric generation is now 3.7×10^{15} Btu/yr.[20] In the early 1970's consumption reached a peak of nearly 4.0×10^{15} Btu/yr. It is expected that the projected increase of 0.1×10^{15} Btu/yr in the utility sector could be almost immediately achieved. Utilities that are now burning oil could easily switch to gas, or simply increase present gas use. However, if new pipeline is required for utilities that previously did not burn gas, the time required for construction could be as long as three years.[5]

5. RATE OF OIL DISPLACEMENT

Based on historical performance of the gas utility industry and the production capacity of conversion burner manufacturers (developed in Phase I of this study), a curve depicting the rate of oil displacement in the residential/commercial sector was prepared (see Figure D-1). By the fifth year after an oil disruption, all of the identified 7.0×10^6 households burning oil in urban areas could be converted to gas. The rate at which these conversions will occur will most likely be defined by the ability of the burner manufacturers to supply the required equipment and the gas utilities to hook up new customers. (This rate, as well as deployment rates for the industrial and utility sectors, has also been adjusted to reflect the time required to increase pipeline capacity to Region 1 (see Section 4).

As determined in Phase I, burner manufacturers could produce 1.5 x 10^6 units in one year. Assuming a modest growth rate of 20 percent, in four years all the necessary burners could be supplied (the displacement rate as a function of burners is depicted as a solid curve on Figure D-1). However, the gas utility industry, even with adequate supplies of burners, would require five years to hook up nearly 7 x 10^6 households. The dashed curve on Figure D-1 illustrates the initial affect of 2.6 x 10^6 immediate conversion by homes already using gas for non-heating purposes (see Table D-3). The growth rate from year one to the fifth year is based on the largest growth in new gas customers (those requiring new distribution lines) in one year, 917,400.[19] This curve dips below that reflecting burner supply in the third year which indicates that the gas utilities would have burners but not have connected the customers. The combination of the two rates of oil displacement is shown on Figure D-4.

The oil displacement curve for the industrial sector (see Figure D-2) is reflected entirely by historical performance. The supply of burners is not expected to be a significant problem due to the relatively small number of conversions and the dual fuel capacity of most industrial firms that have switched from gas to other fuels. More than 9,000 conversions could be performed in the first year (nearly half of the necessary 21,770) based on the ability of the gas utilities displayed in 1961. However, the increase from 188,000 to 209,000 customers (1968 to 1973) required five years to accomplish. Assuming 9,000 initial conversions and subsequent conversions at the same rate achieved during the late 1960's early 1970's, an oil replacement curve depicted on Figure D-2 results. As shown, all of the necessary conversions could be performed in a little over 2 years and 10 months. If the most optimistic scenario is used (i.e., 9,000 conversions every year) all the conversions could be completed in eight fewer months. The curve shown on Figure D-4 reflects the more conservative approach.

Figure D-3 illustrates the estimated rate of oil displacement in the utility sector. Virtually all of the increased gas use will occur immediately. In order to realize all of the displacement potential identified in Section 2, new pipelines may be required. These would take approximately three years to construct[6] and this time period is reflected on Figure D-3. The addition of the utility sector deployment rate to those of the other sectors is depicted on Figure D-4. As shown, the total projected oil displacement of 1,000,000 boe/day is expected to be reached four and one half years after an oil disruption.

6. REFERENCES

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(4) "Residential Energy Conservation Survey: Housing Characteristics, 1980," DOE/EIA-0134, June 1981.

(5) Laurie, D. (Connecticut Natural Gas Co.). Personal communication with N. Hinsey (Gibbs & Hill, Inc.), March 24, 1983.

(6) Setian, C. (Bay State Gas Co.). Personal communication with N. Hinsey (Gibbs & Hill, Inc.), March 24, 1983.

(7) "Comparison of Natural Gas Pricing Analyses," American Gas Association, Arlington, Virginia, June 10, 1983.

(8) "Natural Gas Production Capability," American Gas Association, Gas Supply Committee, Arlington, Virginia, February 1983.

(9) "Emergency Preparedness for Interruption of Petroleum Imports into the U.S.," National Petroleum Council Committee on Emergency Preparedness, pg. 147, April 1981.

(10) "Pipe Line Industry," Vol. 58, No. 1, January 1983.

(11) "Gas Energy Review," American Gas Association, Gas Supply Committee, Vol. 10 No. 3, March 1982.

(12) "Unconventional Gas Sources," National Petroleum Council, December 1980.

(13) Gas-Facts, American Gas Association, Department of Statistics, Arlington, Virginia, pp 25, 33, 1981.

(14) Ibid, pp 33, 39.

(15) Oil and Gas Journal, January 5, 1982.

(16) Oil and Gas Journal, April 11, 1983.

(17) Renna, S. (Brooklyn Union Gas Co.). Personal communication with N. Hinsey (Gibbs & Hill, Inc.), March 25, 1983.

(18) Gas Facts, American Gas Association, Department of Statistics, Arlington, Virginia, pg. 69, 1981.

(19) Ibid, pg. 73.

(20) Ibid, pg. 89.

(21) Jacques, W. (Algonquin Gas Transmission Co.). Personal communication with N. Hinsey (Gibbs & Hill, Inc.), August 22, 1983.

TABLE D-1

PRESENT RESIDENTIAL/COMMERCIAL SECTOR GAS SALES AND PROJECTED 1985 OIL USE

REGION	1980 Gas Sales (a) (10^{12} Btu/yr) RESIDENTIAL	COMMERCIAL	TOTAL	1985 Projected Oil Use (b) (10^{12} Btu/yr) DISTILLATE	KEROSENE	TOTAL
1	143.9	81.0	224.9	315.2	8.0	323.2
2	483.2	178.5	661.7	343.3	8.0	351.3
3	479.0	213.8	692.8	291.1	10.0	301.1
4	364.8	236.4	601.2	118.4	48.2	166.6
5	1680.3	769.7	2450.0	281.1	48.2	329.3
6	452.8	257.3	710.1	88.3	28.1	116.4
7	366.8	227.4	594.2	34.1	34.1	68.2
8	186.6	117.3	303.9	20.1	12.0	32.1
9	599.7	300.4	900.1	14.1	14.1	28.2
10	65.9	59.7	125.6	46.2	4.0	50.2
TOTAL	4823.0	2441.5	7264.5	1551.8	214.8	1766.6

Sources: (a) Gas Facts, American Gas Association, Department of Statistics, Arlington, Virginia, pg. 84, 1981.

(b) Bull, T. (OIA), letter to S.S. Nadgauda (Gibbs & Hill, Inc.), Dec. 17, 1982.

TABLE D-2

ANNUAL GAS REQUIREMENTS OF CONVERSIONS IN THE RESIDENTIAL/COMMERCIAL SECTOR

Region	Res/Comm 1980 Gas Sales (a) (10^{12} Btu/yr)	Res/Comm Projected 1985 (a) Oil Use (10^{12} Btu/yr)	Uniform 50% Penetration: Increase in Gas Use (10^{12} Btu/yr)	Uniform 50% Penetration: Increase Compared to Present (%)	Minimum Regional Increases in Gas Use: Penetration (%)	Minimum Regional Increases in Gas Use: Increase in Gas Use (10^{12} Btu/yr)	Minimum Regional Increases in Gas Use: Increase Compared to Present (%)
1	224.9	323.2	161.6	72	17	53.4	24
2	661.7	351.3	175.6	27	45	159.3	24
3	692.8	301.1	150.5	52	55	166.6	24
4	601.2	166.6	83.3	14	64	106.7	18
5	2450.0	329.3	164.6	7	64	210.8	9
6	710.1	116.4	58.2	8	64	74.5	10
7	594.2	68.2	34.1	6	64	43.6	7
8	303.9	32.1	16.0	5	64	20.5	7
9	900.1	28.2	14.1	2	64	18.0	2
10	125.6	50.2	25.1	20	59	29.7	24
TOTAL	7264.5	1766.6	883.1	12	50	883.1	12

Note: (a) See Table D-1

TABLE D-3

ESTIMATED RES/COMM OIL TO GAS CONVERSIONS COMPARED TO PRESENT FIGURES

Region	Present Res/Comm Gas Customer Profile: Number of 1980 Res/Comm Gas Customers (10^3)	Present Res/Comm Gas Customer Profile: Number of 1980 Non-Heating Customers (10^3)	Oil to Gas Conversions: Required Number of Conversions (10^3)	Oil to Gas Conversions: Conversions Requiring New Distribution Lines (10^3)	Conversions Requiring New Distribution Lines as Percentage of Present Gas Customers (%)
1	1,725	583	435	144	8
2	5,657	2,562	1,137	-	-
3	4,270	725	1,170	808	19
4	4,239	106	1,118	1,065	25
5	11,546	800	1,144	744	6
6	5,740	25	853	841	15
7	3,054	82	328	287	9
8	1,604	8	159	155	10
9	8,211	322	222	61	1
10	756	35	307	289	38
TOTAL	46,802	5,248	6,973(a)	4,394	9

Note: (a) 6,880,000 Residential and 93,000 commercial conversions.

Source: Gas Facts, American Gas Association, Department of Statistics, Arlington, Virginia, ppg. 74, 78, 1981.

TABLE D-4

PRESENT INDUSTRIAL SECTOR GAS SALES AND PROJECTED 1985 OIL USE

Region	Industrial (a) 1980 Gas Sales (10^{12} Btu/yr)	1985 Projected Industrial Oil Use (b) (10^{12} Btu/yr)			Industrial Oil Use Potentially Displaced by Conversions to Either CWM, Coal or Wood (10^{12} Btu/yr)(c)	Projected Industrial Oil Use of Likely Candidates for Conversion to Gas (10^{12} Btu/yr)
		Residual	Distillate	Total		
1	70.1	236.9	70.2	307.1	52.2	254.9
2	233.9	429.6	156.6	586.2	92.3	493.9
3	491.4	172.6	50.2	222.8	38.1	184.7
4	963.4	361.4	50.2	411.6	85.3	326.3
5	1,456.0	194.8	52.2	247.0	42.2	204.8
6	2,793.6	285.1	66.2	351.3	66.2	285.1
7	497.4	22.1	16.1	38.2	5.5	32.7
8	198.0	52.2	10.0	62.2	10.3	51.9
9	996.4	36.1	20.1	56.2	9.5	46.7
10	161.7	26.1	10.0	36.1	5.8	30.3
TOTAL	7,861.9	1,816.9	501.8	2,318.7	407.4	1,911.3

Source: (a) Gas Facts, American Gas Association, Department of Statistics, Arlington, Virginia, pg. 84, 1981.
(b) Bull, T. (OTA), letter to S.S. Nadgauda (Gibbs & Hill, Inc.), December 17, 1982.
(c) See Appendices A and B (Figures shown are the largest regional oil displacements of any one fuel and are not total displacement of all three since these fuels compete for the same market segment).

TABLE D-5

ANNUAL GAS REQUIREMENTS OF CONVERSIONS IN THE INDUSTRIAL SECTOR

Region	Industrial (a) 1980 Gas Sales (10^{12} Btu/yr)	Projected Industrial Oil Use of Likely Candidates for Conversion to Gas (10^{12} Btu/yr) (a)	Uniform 48% Penetration		Minimum Regional Increases in Gas Use		
			Increase in Gas Use (10^{12} Btu/yr)	Increased Compared to Present Use (%)	Penetration (%)	Increase in Gas Use (10^{12} Btu/yr)	Increase Compared to Present Use (%)
1	70.1	254.9	121.5	173	4	11.3	16
2	233.9	493.9	235.5	101	8	37.8	16
3	491.4	184.7	88.1	18	43	79.3	16
4	963.4	326.3	155.6	16	48	155.6	16
5	1,456.0	204.8	97.6	7	100	204.8	14
6	2,793.6	285.1	135.9	5	100	285.1	10
7	497.4	32.7	15.6	3	100	32.7	7
8	198.0	51.9	24.7	12	62	32.0	16
9	966.4	46.7	22.3	2	100	46.7	5
10	161.7	30.3	14.5	9	86	26.1	16
TOTAL	7,861.9	1,911.3	911.3	12	48	911.3	12

Note: (a) Table D-4

TABLE D-6

PRESENT UTILITY SECTOR (ELECTRIC GENERATION) GAS SALES AND PROJECTED 1985 OIL USE

Region	1980 Utility Gas Sales (10^{12} Btu/yr)	1985 Projected Utility Oil Use (10^{12} Btu/yr)			Utility Oil Use Potentially Displaced by CWM Conversions (10^{12} Btu/yr) (a)	Projected Utility Oil Use of Likely Candidates for Conversion to Gas (10^{12} Btu/yr)
		Residual	Distillate	Total		
1	7.0	349.3	4.0	353.3	209.8	143.5
2	203.9	337.3	4.0	341.3	299.4	41.9
3	100.4	100.4	40.2	140.6	-	140.6
4	276.3	162.6	-	162.6	162.6	0
5	73.9	32.1	59.2	91.3	-	91.3
6	2,300.1	6.0	-	6.0	-	6.0
7	135.0	2.0	-	2.0	-	2.0
8	41.4	-	-	-	-	-
9	596.0	194.7	2.0	196.7	194.7	2.0
10	30.1	4.0	-	4.0	-	4.0
TOTAL	3,681.1	1,188.4	109.4	1,297.8	866.5	431.3

Note: (a) Appendix A

Source: Gas Facts, American Gas Association, Department of Statistics, Arlington, Virginia, pg. 89, 1981.
Bull, T. (OTA), Letter to S.S. Nadgauda (Gibbs & Hill, Inc.), December 17, 1982.

TABLE D-7

ANNUAL GAS REQUIREMENTS OF CONVERSIONS IN THE UTILITY SECTOR

Region	Utility 1980 Gas Sales (a) (10^{12} Btu/yr)	Projected Utility Oil Use of Likely Candidates for Conversion to Gas (10^{12} Btu/yr)(a)	Uniform 48% Penetration		Minimum Regional Increases in Gas Use		
			Increase in Gas Use (10^{12} Btu/yr)	Increase Compared to Present (%)	Penetration (%)	Increase in Gas Use (10^{12} Btu/yr)	Increase Compared to Present (%)
1	7.0	143.5	68.4	977	12	16.7	239
2	203.9	41.9	20.0	10	100	41.9	21
3	17.4	140.6	67.0	385	30	41.7	240
4	276.3	-	-	-	-	-	-
5	73.9	91.3	43.4	59	100	91.3	124
6	2,300.1	6.0	2.9	<<1	100	6.0	<<1
7	135.0	2.0	1.0	1	100	2.0	1
8	41.4	-	-	-	-	-	-
9	596.0	2.0	1.0	<<1	100	2.0	<<1
10	30.1	4.0	1.9	6	100	4.0	13
TOTAL	3,681.1	431.3	205.6	6	48	205.6	6

Note: (a) Table D-6

TABLE D-8

1981 ACTUAL U.S. GAS SUPPLY

SOURCE	(10^{15} Btu)
Conventional	19.1
Lower 48	19.1
Alaska	-
Non-Conventional	0.2
Tight Sands	0.2
Devonian Shale	-
Coal Seams	-
Geopressured Brines	-
Biomass	-
Foreign Imports	1.0
Canada	0.8
Mexico	0.1
LNG (Algeria)	0.1
Substitutes	0.1
SNG	0.1
Coal Gasification	-
TOTAL	20.4

Source: "Monthly Energy Review," EIA, 1982.

TABLE D-9

1985 PROJECTIONS OF U.S. GAS SUPPLY
(10^{15} Btu/yr)

Reference: Date of Projection:	American Gas Association (1982) [1]	Energy Information Administration (1983) [2]	National Petroleum Council (1980) [3]	National Research Council (1979) [4]	-
notes:	North American focus		$5/MCF	"business as usual" scenario	-
SOURCES					Largest Difference Between Projections
Conventional	17.0	14.8	16.3	13.5 [5]	3.5
lower 48	17.0		16.1		0.9
Alaska	-	0	0.2		0.2
Non-Conventional	0.5 [5]	Included in	1.1	0	1.1
Tight Sands		conventional	0.5		0.5
Devonian Shale		supply figure	0.4		0.4
Coal Seams			0.2		0.2
Geopressured Brine			<0.01		-
Biomass			-		-
Substitutes	0.4	0.1 [5]	0.1 [5]	0.4	0.3
SNG	0.3			0.1 [4]	0.2
Coal Gasification	0.1			0.3	0.3
U.S. total	17.9	14.9	17.5	13.9	4.0
Foreign	2.7	1.4 [5]	0.8 [5]	2.7 [5]	1.5
Canada	1.5				
Mexico	0.5				
LNG	0.7			1.7	1.0
TOTAL	20.6	16.3	18.3	16.6	4.3

Notes to Table D-9:

[1] "Gas Energy Review," American Gas Association, Gas Supply Committee, Vol. 10, No. 3, March 1982.

[2] "1982 Annual Energy Outlook," EIA, DOE/EIA-0383 (82), April 1983.

[3] "Unconventional Gas Sources," Natural Petroleum Council, Dec. 1980.

[4] "U.S. Energy Supply Prospects to 2010," Report of the Supply and Delivery Panel to the Committee on Nuclear and Alternative Energy Systems, Washington, D.C., National Academy of Sciences, National Resources Council, 1979.

[5] Complete breakdowns of estimate unaviailable.

[4] Not considered by NRC; present supply is shown.

TABLE D-10

1990 PROJECTIONS OF U.S. GAS SUPPLY
(10^{15} Btu/yr)

Reference: Date of Projection:	American Gas Association (1982) [1,2]	Energy Information Administration (1983) [3]	National Petroleum Council (1980) [4]	National Research Council (1979) [5]	-
Notes:	Maximum Effort [6]	High Price Path	$9/MCF	National Commitment	-
					Largest Difference Between Projections
SOURCES					
Conventional	17.4	15.8 [7]	15.7	18.0 [7,8]	2.3
Lower 48	17.3		14.6		2.7
Alaska	0.1	0	1.1		1.1
Non Conventional	1.8 [7]	Included in	3.8		2.0
Tight Sands	0.9	conventional	2.5		1.6
Devonian Shale		supply figure	0.6	-	0.6
Coal Seams			0.6	-	0.6
Geopressured Brine			0.05	-	0.05
Biomass	0.1		-	0.9	0.9
Substitutes	1.0	0.1 [7]	0.1 [7]	1.8	1.7
SNG	0.3			0.1 [9]	0.2
Coal Gasification	0.7			1.7	1.0
U.S. Total	20.2	15.9	19.6	20.7	4.8
Foreign	3.5	1.3 [7]	0.8 [7]	5.5 [7]	4.7
Canada	1.7				
Mexico	1.0				
LNG	0.8			4.5	
TOTAL	23.7	17.2	20.4	26.2	9.0

Notes to table D-10:

(1) "Gas Energy Review," American Gas Association, Gas Supply Committee, Vol. 10, No. 3, March 1982.

(2) Ibid, Vol. 10, No. 12, Dec. 1982.

(3) "1982 Annual Energy Outlook," EIA, DOE/EIA-0383 (82), April 1983.

(4) "Unconventional Gas Sources," Natural Petroleum Council, Dec. 1980.

(5) "U.S. Energy Supply Prospects to 2010," Report of the Supply and Delivery Panel to the Committee on Nuclear and Alternative Energy Systems, Washington, D.C., National Academy of Sciences, National Resource Council, 1979.

(6) A combination of 1990 projections under normal conditions and 1987 projections based on an aggressive top priority program to increase gas supply.

(7) Complete breakdown unavailable.

(8) Includes tight sands gas, volumes not specified (assumed to be relatively small).

(9) Not considered by NRC; present supply is shown.

TABLE D-11

SUMMARY OF INCREASED GAS USE OF ALL SECTORS DUE TO CONVERSIONS FROM OIL (a)

Region	Total Gas Sales to All Sectors (10^{12} Btu/yr)	ESTIMATED INCREASE IN GAS USE DUE TO CONVERSIONS FROM OIL (10^{12} Btu/yr)				Increase Compared to Present Use (%)
		Res/Comm	Industrial	Utility	Total	
1	302.0	53.4	11.3	16.7	81.4	27
2	1099.5	159.3	37.8	41.9	239.0	22
3	1201.6	166.6	79.3	41.7	287.6	24
4	1840.9	106.7	155.6	-	262.3	14
5	3979.9	210.8	204.8	91.3	506.9	13
6	5803.8	74.5	285.1	6.0	365.6	6
7	1226.6	43.6	32.7	2.0	78.3	6
8	543.3	20.5	32.0	-	52.5	10
9	2492.5	18.0	46.7	2.0	66.7	3
10	317.4	29.7	26.1	4.0	59.8	19
TOTAL	18,807.5	883.1	911.3	205.6	2000.0	11

(a) TABLES D-2, D-5, D-7

TABLE D-12

EXCESS CAPACITY OF SELECTED GAS PIPELINES

	Deliveries in 1981 (BCF)	Design Capacity (BCF)	Excess Capacity (BCF)
To Regions 1, 2 and 3:			
Tennessee Gas Pipeline Co. (TENNECO)	1861	1863	2
Transcontinental Gas Pipeline Co. (TRANSCO)	902	1132	230
Texas Eastern Transmission Co.	1015	1488	473
Columbia Gas Transmission Corp.	1056	1210*	154
TOTAL	4834	5693	859
To Regions 9 and 10:			
El Paso Natural Gas Co.	1360	1423	63
Pacific Gas Transmission Co.	399	474	75
Transwestern Pipeline Co.	314	355*	41
Northwest Pipeline Co.	318	719	401
TOTAL	2391	2971	580

Sources: Form 10-k Annual Reports, Securities and Exchange Commission, Wash. D.C., 1982
* Highest historical deliveries

TABLE D-13

PRESENT GAS STORAGE CAPACITY COMPARED TO INCREASED REQUIREMENTS

Region	GAS STORAGE CHARACTERISTICS (AS OF 12/31/81)			Required Storage Due to Increases in Gas Consumption (10^{12} Btu)
	Number of Reservoirs	Working Gas (10^{12} Btu)	Unused Capacity (10^{12} Btu)	Undeveloped Capacity (10^{12} Btu)	
1	-	-	-	-	7.0
2	21	48.4	17.9	2.6	20.6
3	100	478.5	77.3	3.5	21.5
4	26	135.3	0.4	-	13.8
5	135	877.8	107.5	150.8	27.2
6	48	603.6	186.3	7.3	9.6
7	29	225.4	38.8	92.0	5.6
8	23	221.2	43.2	-	2.6
9	9	204.5	50.3	-	2.3
10	2	11.3	-	-	3.9
TOTAL	393	2,806.0	522.1	256.2	114.1

Source: "The Underground Storage of Gas in the U.S. and Canada," American Gas Association, Arlington, Va, Dec. 31, 1981.

TABLE D-14

ESTIMATED RES/COMM OIL TO GAS CONVERSIONS AS COMPARED TO HISTORICAL FIGURES

Region	Number of Res/Com (a) Customers in 1980 (10^3)	Conversions Requiring (a) New Distribution Lines (10^3)	Largest Historical 5 year (b) Increase in New Customers (10^3)
1	1,725	144	196
2	5,657	-	371
3	4,270	808	437
4	4,239	1,065	607
5	11,546	744	1,520
6	5,740	841	552
7	3,054	287	331
8	1,604	155	225
9	8,211	61	887
10	756	289	201
TOTAL	46,802	4,394	5,327

Notes:

(a) Table D-3

(b) Gas Facts, American Gas Association, Department of Statistics, Arlington, Virginia, pg. 78, 1981.

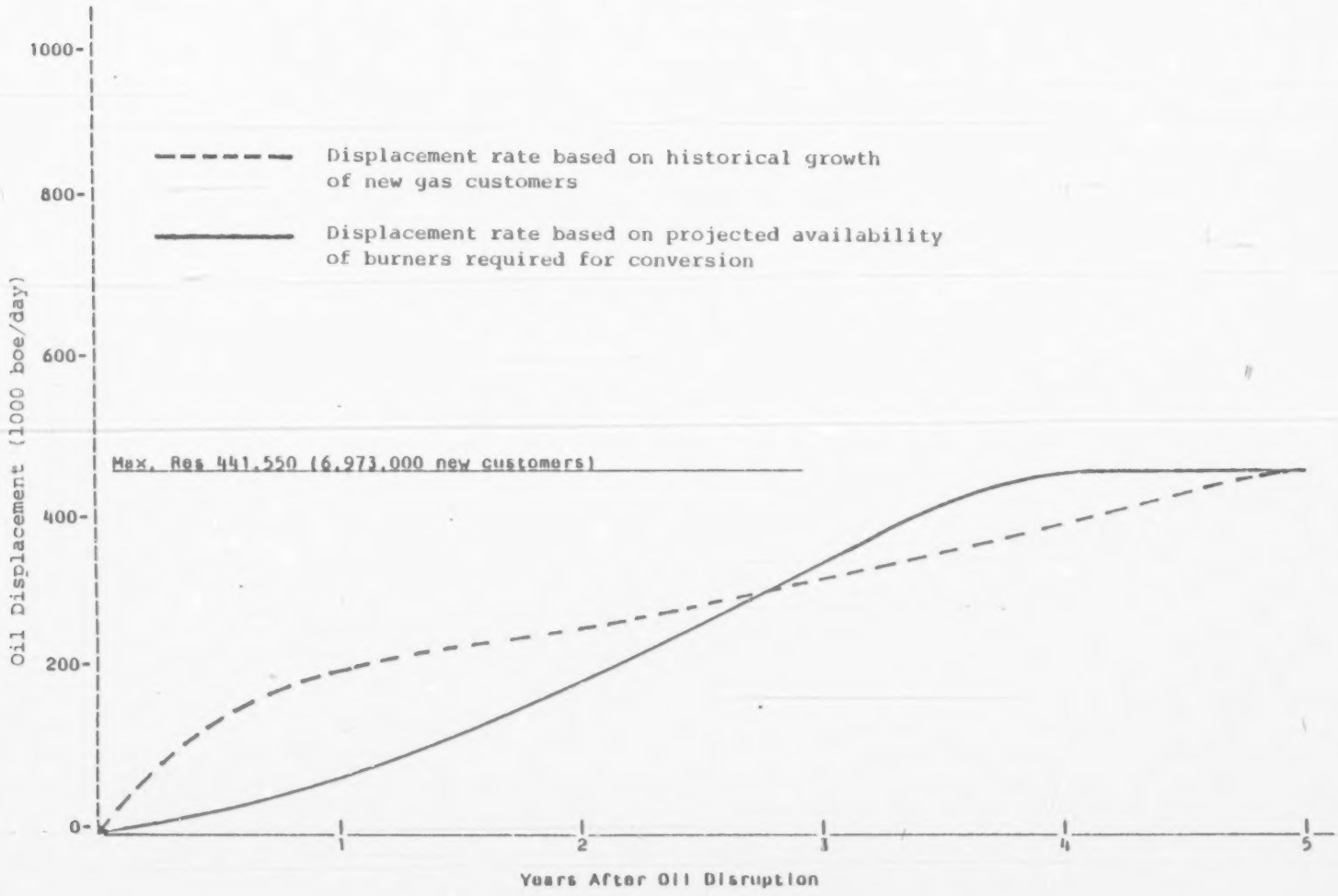

FIGURE D-1

RATE OF OIL DISPLACEMENT:
CONVERSION TO NATURAL GAS IN THE
RES/COMM. SECTOR

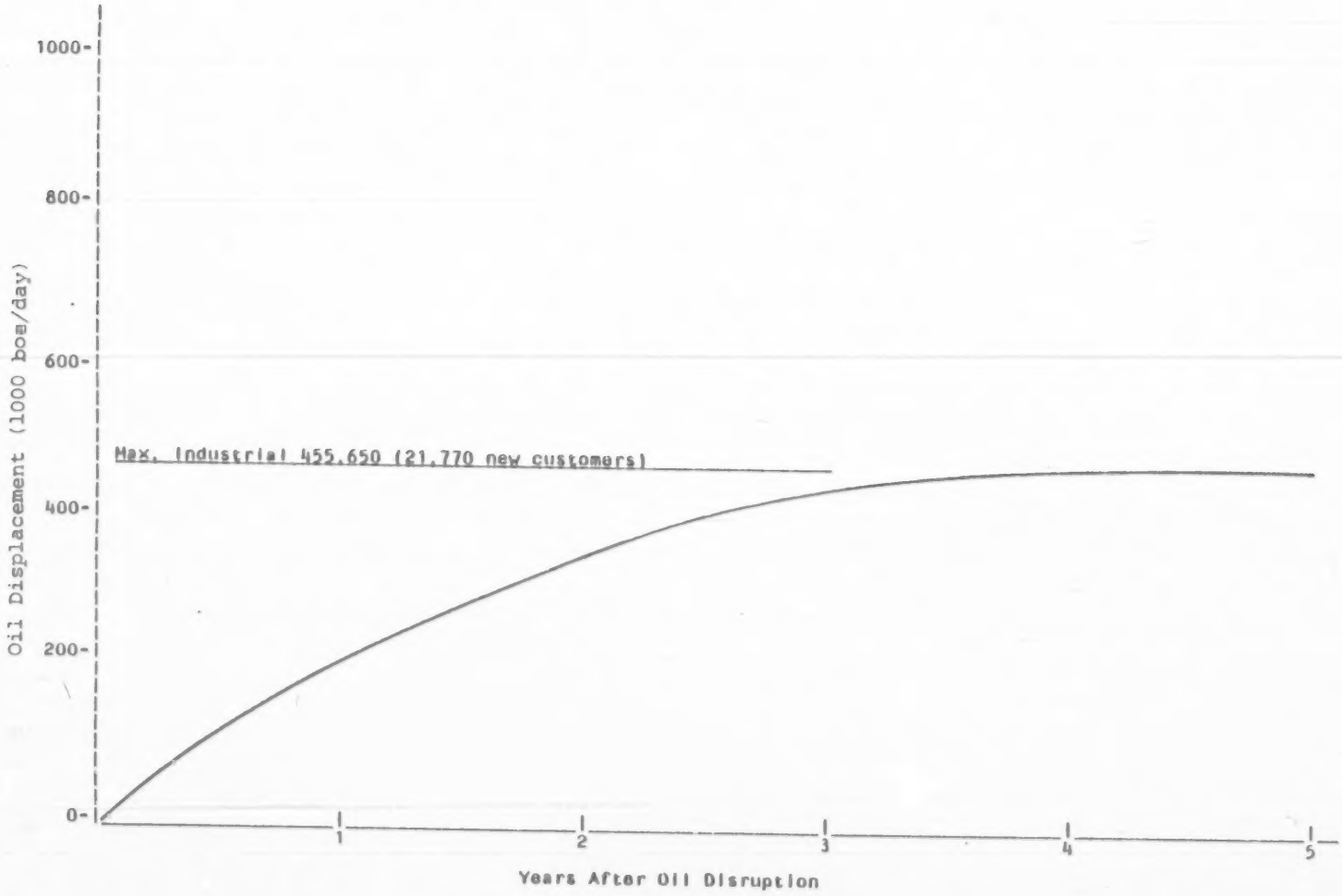

FIGURE D-2

RATE OF OIL DISPLACEMENT:
CONVERSION TO NATURAL GAS IN THE
INDUSTRIAL SECTOR

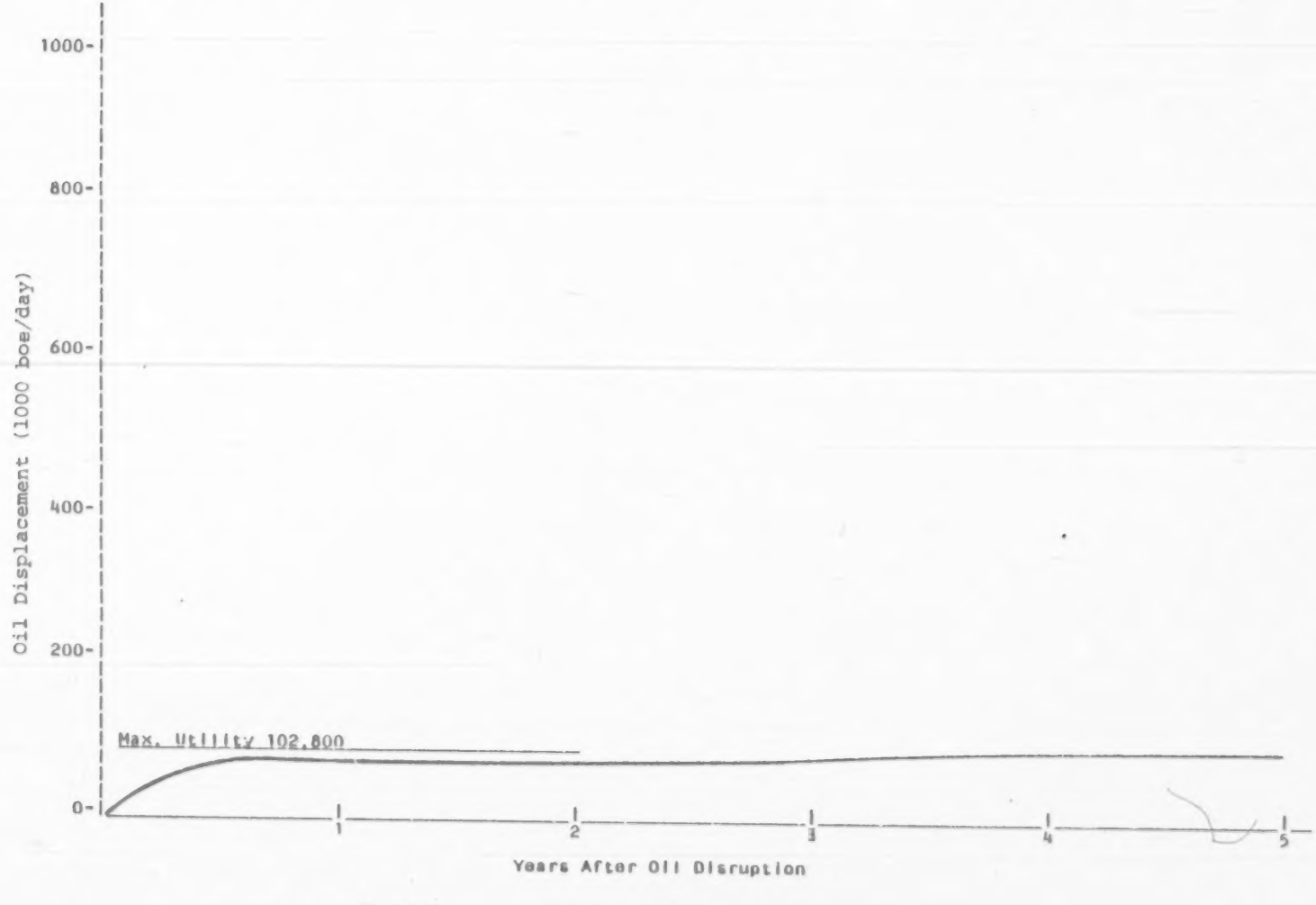

FIGURE D-3

RATE OF OIL DISPLACEMENT;
CONVERSION TO NATURAL GAS IN THE
UTILITY SECTOR

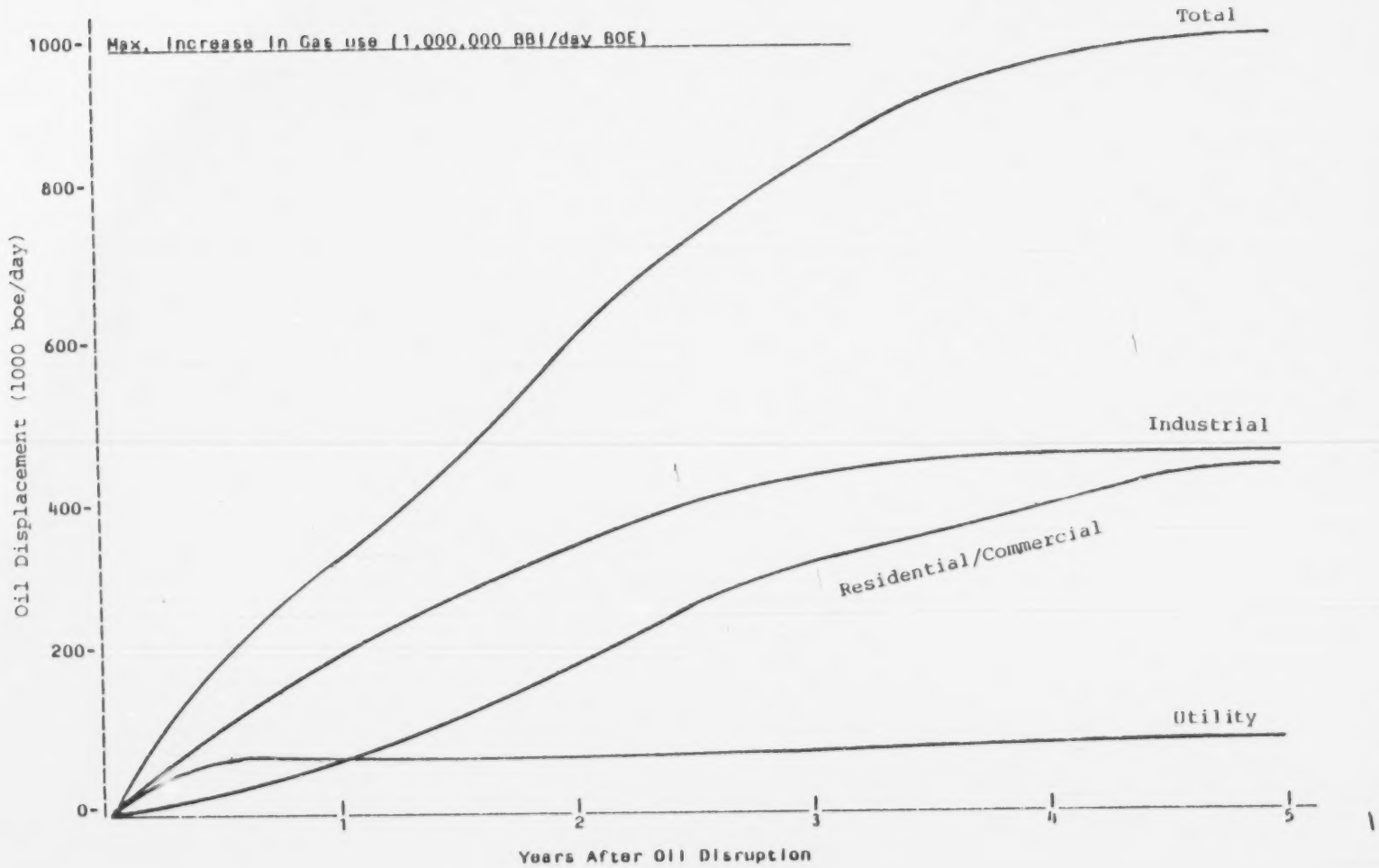

FIGURE D-4

RATE OF OIL DISPLACEMENT;
CONVERSION TO NATURAL GAS IN THE
RES/COMM., INDUSTRIAL AND UTILITY SECTOR

E. NATURAL GAS AND LIQUEFIED PETROLEUM GAS IN TRANSPORTATION

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1. Introduction

2. Assessment of Equipment and Manpower Constraints

3. Deployment Rate

4. References

FIGURE

E-1 Oil Replacement Rate for CNG and LPG Vehicle Conversions

E-2 Combined Oil Replacement Rate for CNG and LPG Vehicle Conversions

1. INTRODUCTION

The Gibbs & Hill (G&H) Phase I report identified compressed natural gas (CNG) and liquefied petroleum gas (LPG) powering of vehicles as a possible oil replacement technology. The preliminary oil replacement potential by this technology was estimated to be as follows:

CNG: 375,000 boe/d (conversion of 5.34 million fleet vehicles)

LPG: 35,000 boe/d

In this Appendix, we examine further the noninstitutional constraints - equipment and manpower limitations - which were identified in the G&H Phase I report for deployment of this technology. Based on the constraints analysis, we have reassessed downwards the oil replacement potential over the 1985-1990 period.

2. ASSESSMENT OF EQUIPMENT AND MANPOWER CONSTRAINTS

The major potential constraints in converting vehicles to CNG and LPG powering are in the following areas:

- Natural gas compressors
- Gas cylinders
- Regulators and gas mixers
- LPG tanks
- Trained mechanics.

a. Natural Gas Compressors

The number of compressors required for CNG refueling stations depends upon the number of vehicle fleets and typical fleet driving characteristics. The following is assumed for the typical fleet[1]:

- 20 to 40 vehicles
- 90 miles average daily travel per vehicle
- 21 mpg average fuel economy.

For a 20-vehicle fleet, the compressor and high pressure storage cascade are typically sized for slow-fill of 15 vehicles and the quick-fill of 5.[2] Typical vehicle cylinders have capacity for 325 to 350 scf of natural gas at 2400 psig.[1,2] A vehicle in the aforementioned typical fleet requires two cylinders per vehicle. Refueling 15 vehicles in a 10-hour period requires a

compressor rating of approximately 20 scfm, a size which is typical of fleet refueling stations.[2,3] The remaining five vehicles can be quick-filled (3 to 5 minutes) from the storage cascade cylinders at 3600 psig. These have sufficient storage capacity to deliver 3500 scf of natural gas when going from the 3600 to the 2400 psig pressure level.

For larger fleets, one manufacturer of CNG vehicle conversion equipment simply uses multiples of the compressor used for the small fleets.[3] For planning purposes we have followed the same design philosophy, thus for the typical 40-vehicle fleet, two 20 scfm compressors are designated.

Commercial CNG equipment suppliers do not provide spare compressors because reliability has been excellent and the fleet operators have been able to schedule maintenance in concert with fleet operating regimen. Thus, the number of compressors required to convert 5.34 million fleet vehicles is 267,000 (= $5.34 \times 10^6/20$).

In 1980 a total of 5,512 gas compressors, which includes compressors for all types of gases, were shipped from manufacturers in the United States[4]. This total is close to the historical high of 5,770 gas compressors shipped in 1974. In marked contrast, in 1980 1,576,000 air compressors were shipped[4].

Gas compressors are more complex in design than air compressors because of stricter sealing requirements, higher pressures, and precautions that must be taken into account with regard to sparking and gas/lubricant compatibility. The compressors for CNG stations consist of 3 or 4 stages with provisions for intercoolers and condensate traps to provide a dependable source of high pressure gas.[2,3] Because of the complexities of gas compressors versus air compressors, the manufacturing and design techniques are more precise and demanding. Consequently, the U.S. manufacturing capability of air compressor is not used in assessing capacity to manufacture compressors for CNG filling stations.

A major manufacturer of CNG compressors has shipped a maximum of 100 units per year but estimates that, with available manufacturing capacity, output could be 500 units per year.[5] With sales of CNG compressors above 500 units per year this manufacturer could produce additional units, but this would require additional manufacturing equipment, some with long lead times.

Assuming a 70 percent capacity utilization for gas compressor manufacturing facilities, an additional 2400 gas compressors could be manufactured currently in the U.S. However, since the number of gas compressors shipped represents all types of designs and sizes, much of the existing manufacturing capability would not have specialized tooling or other manufacturing equipment for the type and size of compressor required in CNG powering of vehicles. Based on current gas compressor shipments and anticipated capacity expansion which is based on demand, it is estimated that in the first year of the oil disruption 2,000 CNG compressors could be shipped. With sustained demand in subsequent years manufacturers would be expected to tool-up for CNG compressors. Historically, manufacturers supplying the energy industry build new production capacity in response to a continuing demand[6], such as that projected for CNG vehicles. Although the historical growth rate of sales of gas compressors in the U.S. over the last 20 years is only 3.1 percent per year[4], an annual growth of 50 to 100 percent could be assumed in the crisis situation. With this growth rate scenario, a total of 26,000 to 62,000 compressors for CNG applications could be shipped in the 5-year timeframe.

Thus, it is concluded that the availability of compressors will limit the number of CNG fleet vehicle conversions in a five-year period to 0.5 to 1.2 million vehicles.

b. Gas Cylinders

Two CNG cylinders (each 10-5/8 in. diameter x 40 in. long) are installed per vehicle. In addition, twenty storage cylinders (each 10-5/8 in. diameter x 56 in. long providing approximately 200 scf of CNG) are required for a 20 vehicle fleet for quick-filling 5 vehicles at a refueling station. Thus, the total vehicle and storage cylinders required in five years to achieve the fleet vehicle oil replacement potential is approximately 16×10^6 ($= 2 \times 5.34 \times 10^6 + 5.34 \times 10^6$).

The availability of over 3 million cylinders per year for both vehicle and filling station storage of CNG is a potential constraint because of the structural characteristics of the cylinders dictated by Department of Transportation (DOT) regulations. The cylinders must be seamless which limits the number of manufacturers to those that have the metal working equipment for piercing, deep drawing and hot spinning of cylinders in the size range of interest with sufficient wall

thickness to contain the 2,400 to 3,600 psig pressures. Of the approximately 25 cylinder manufacturers in the U.S., only 6 or 7 of these have the required equipment to produce CNG-type cylinders.[7,8,9]

DOT has approved three manufacturing methods for cylinders[7]:

1) Billet piercing to a cup shape followed by drawing to the required length and wall thickness and subsequent hot spinning to close the open end.

2) Deep drawing of sheet material to create a cup followed by hot spinning of the open end.

3) Hot spinning both open ends of seamless pipe.

The first two methods are those most commonly employed today because the seamless pipe required for the third method is made of comparatively expensive material and thus a cylinder produced by the third method is not cost competitive. Current demand for CNG-type cylinders is 400,000 to 600,000 per year with an additional available industrial capacity, using manufacturing methods 1 and 2, of 800,000 per year.[7, 10] Additional output above the 1.2 to 1.4 million level with methods 1 and 2 would require capital investment by manufacturers in piercing and deep drawing equipment.

The equipment for manufacturing methods 1 and 2 is expensive and relatively long-lead in nature. In a surge demand situation, manufacturers could resort to method 3 which requires only hot spinning equipment. The additional manufacturing capacity for CNG-type cylinders would increase substantially above the 800,000 per year level in a short period of time using method 3 for the following reasons:

1) Cylinder manufacturers have hot spinning capacity for an additional 200,000 to 300,000 cylinders per year above the 800,000 added increment.

2) Other types of manufacturers have hot spinning equipment and they could begin manufacturing cylinders. (However, at present these manufacturers do not sell cylinders because method 3 is not cost competitive with methods 1 and 2.)

3) Hot spinning is performed by placing the pipe section in the hollow spindle of a lathe-type machine.[12] This equipment is neither massive nor

complex as is the piercing and deep drawing equipment and lead-times, for procurement, are estimated to be in the 3 to 6 month range.

Based on the above, it is concluded that the availability of cylinders would not constrain the oil replacement potential of CNG vehicles. Present manufacturing capability in a five-year period could provide at least 5 million additional cylinders for CNG and the remaining amount if needed to achieve the full 16 million potential can be realized by the hot spinning method of manufacture. In reality only 1.5 to 3.7 million cylinders will be required based on limited availability of CNG compressors.

c. Regulators and Gas Mixers

Pressure regulators and gas mixers are key components in conversion of vehicles to CNG and LPG fuels. The potential CNG fleet vehicle and LPG private vehicle conversions total 6 to 7 million. Currently, the CNG vehicle conversion industry is small compared to the LPG conversion equipment capability. However, the regulators and mixers for each technology are similar and the extensive manufacturing capability for LPG equipment can be applied to manufacture of regulators and gas mixers for CNG vehicles. Since some of the CNG equipment is proprietary in nature, it is assumed that CNG equipment suppliers will utilize the existing LPG manufacturing capability through licensing or similar arrangements.

Current manufacturing capabilities can provide conversion equipment for 1/2 million vehicles per year.[13] Thus, equipment for 2-1/2 million vehicles could be available in the five-year period and, based on the limitation in vehicle conversions imposed by compressors, the availability of gas regulators and mixers will not pose a constraint.

d. LPG Tanks

Approximately 1 million vehicle tanks would be required in a five-year period to achieve the oil replacement of 35,000 boe/d of LPG conversions. These tanks are the same in design and structure as those currently used for portable heaters, recreational vehicles, and cooling equipment. An additional 200,000 tanks per year could be made by the domestic manufacturers of this equipment.[10] Thus, LPG tank availability is not a constraint.

e. Trained Mechanics

The availability of mechanics sufficiently trained and skilled for installation and maintenance of equipment represents a potential constraint. One supplier of CNG conversion systems requires a two-week training period for mechanics designated by the fleet operator.[14] In the typical fleet, a vehicle is replaced every two to three years. It is assumed that in a CNG powered vehicle fleet, the CNG equipment would be reused once over a five year period when an old vehicle is replaced by a new one. Since the CNG equipment installation requires eight hours and its removal requires four hours, a total of twenty mechanic manhours are required per vehicle for installation, removal and reinstallation. Beyond the installation, removal, and reinstallation of equipment in vehicles, the time required to maintain a CNG-powered vehicle is equivalent to that of a conventional one. Assuming that during the five-year period all CNG and LPG conversion equipment is transferred once to an other vehicles, the total number of trained mechanics required for 6 to 7 million vehicles in five years is approximately 13,000 to 15,000 from:
(6 to 7 x 10^6 vehicles) (20 hrs/vehicle)/
(1880 hrs/mechanic-year) (5 years).

The total number of automobile mechanics in the U.S. is 923,000.[15] The 13,000 to 15,000 increase represents only a 1.5 percent increase and is not considered a constraint. The individuals assigned to the CNG fleet refueling stations for refueling operations need not be trained mechanics and should not represent an increase in the labor normally associated with bus, truck, taxi, utility, etc. fleets. Even if one additional individual was required per fleet for refueling operations, the total is a very small fraction of the total work force and, since it is not a job requiring high skill, this would not be a constraint.

3. DEPLOYMENT RATE

The oil replacement rate of CNG vehicle conversions will be dictated by the ability to provide CNG compressors. Using a delivery of 2,000 compressors in the first year and 50 and 100 percent growth rates in shipments thereafter, the oil replacement will reach 37,000 and 87,000 boe/d, respectively, at the end of the five-year period as shown in Figure E-1.

For LPG vehicle conversions, there are no equipment or manpower constraints for achieving the full oil replacement

of 35,000 boe/d. The oil replacement rate will depend on the rate at which additional LPG is available from additional natural gas production, which is not expected to be appreciable until two years after the oil disruption. As discussed in the Phase I report, this oil displacement level is based on increased natural gas production only and not that available from oil production. Natural gas with low liquids content was also assumed. It is important to note that the available 35,000 boe/d of LPG is based on no interruptions in existing supplies of LPG.

The oil replacement rate for LPG conversions, shown in Figure E-1, reflects the gradual increase in natural gas production to the 2 TCF/year level. The combined oil replacement rate for CNG and LPG conversions is shown in Figure E-2.

In the event of an oil supply disruption there will be conservation and fuel switching to electricity by residential and industrial users of LPG. Using 150,000 boe/d as the upper limit of LPG that can be saved by these conservation and fuel switching efforts provides sufficient fuel for approximately 4.3 million vehicle conversions. Adding the 1 million vehicles that can be fueled by the LPG from additional natural gas production results in an average number of yearly conversions of approximately 1 million in the five-year timeframe. The availability of tanks, regulators and gas mixers for this number of conversions must be examined.

There are twenty-nine manufacturers of LPG tanks and cylinders in the U.S.A. [16]. Some of these manufacturers specialize in the vehicle tanks, others in the cylinders commonly used for cooking applications. Regardless of their current manufacturing specialty facilities can be converted to manufacture either product since the fabrication methods are essentially identical.[17-19] Based on this flexibility the industry could manufacture an additional 1 to 1.5 million tanks for vehicles.[17-19] An American Society of Mechanical Engineers (ASME) certification is needed to manufacture the vehicle tanks which may delay for approximately a year the ability of cylinder manufacturers to switch to vehicle tanks.

As discussed earlier current manufacturing capabilities can provide regulators and gas mixers for 1/2 million vehicles per year. These components, however, are very similar to other industrial equipment dealing with gas distribution and measurement and it is anticipated that with sufficient market incentives the other 1/2 million per year could be

manufactured by subcontract from the vehicle conversion kit manufacturers to other manufacturers.

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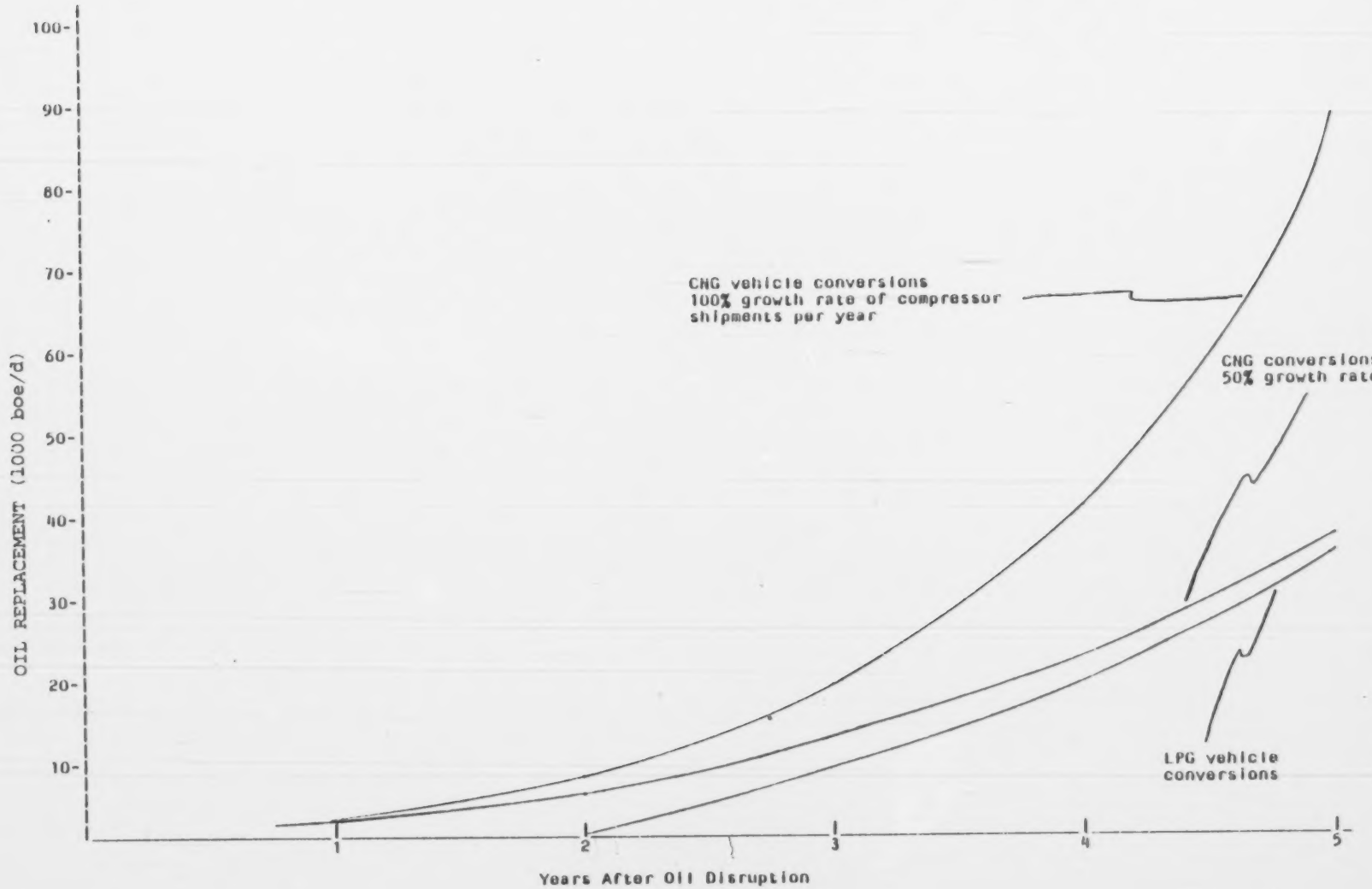

FIGURE E-1

OIL REPLACEMENT RATE FOR CNG AND
LPG VEHICLE CONVERSIONS

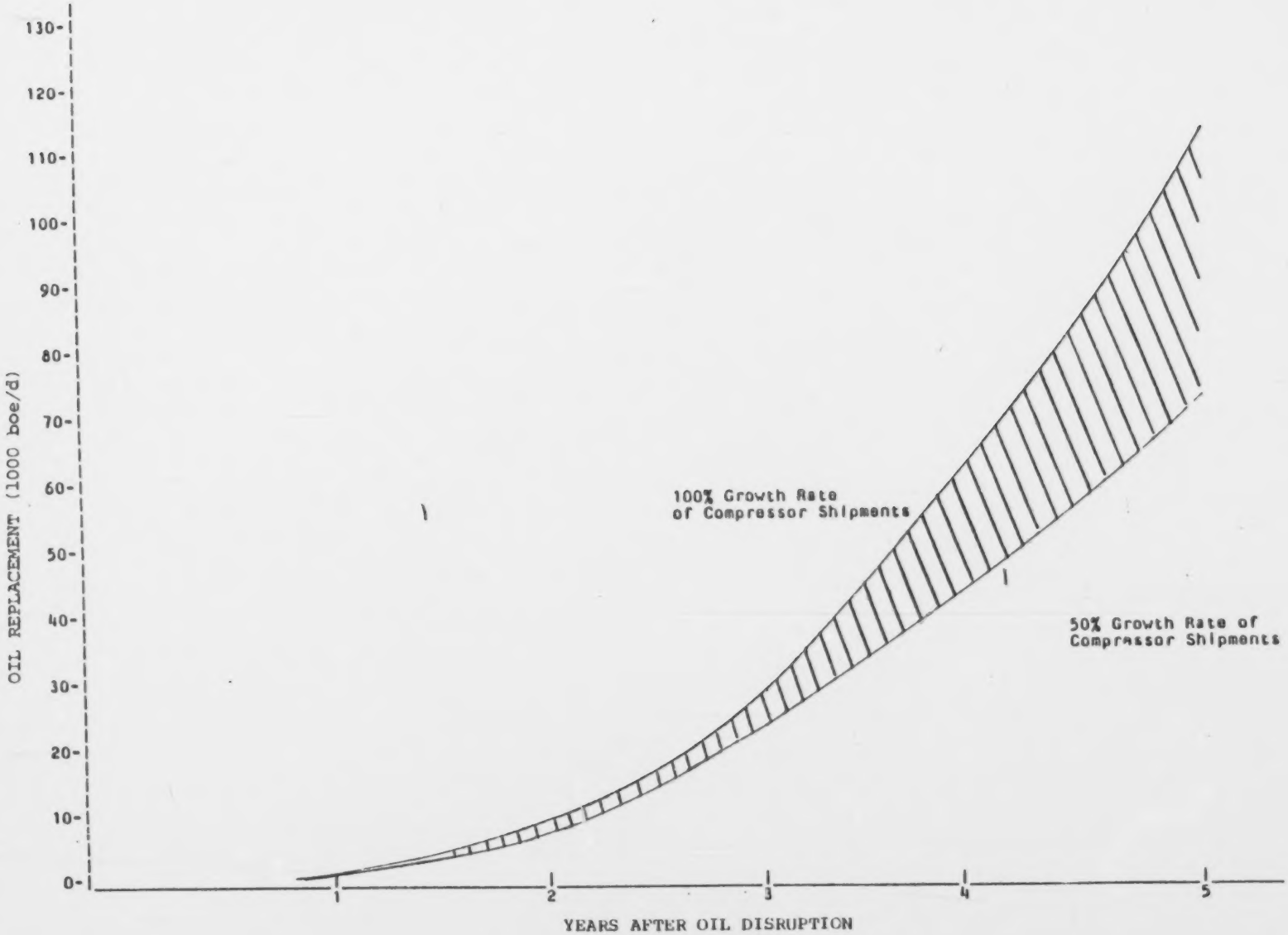

FIGURE E-2
COMBINED OIL REPLACEMENT RATE FOR
CNG AND LPG VEHICLE CONVERSIONS

F. ETHANOL FROM CORN

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1. Introduction

2. Identification of Critical Components

3. Assessment of Potential Constraints

4. References

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1. Schedule For Engineering and Construction 50 MMGPY Ethanol Plant

2. Oil Displacement Curve - Corn to Ethanol Technology

1. INTRODUCTION

The Gibbs & Hill (G&H) Phase I report identified ethanol production from corn as an option which could be deployed rapidly under an imported oil cut-off scenario. In this Appendix we have assessed potential constraints to rapid deployment based on a typical facility configuration.

2. IDENTIFICATION OF CRITICAL COMPONENTS

The technology is proven and standardized designs are commercially available for plant capacities in the 10-100 MM gallons per year (GPY) range[1,2]. A typical corn to ethanol plant can be divided into the following areas:[3]

- Raw material receiving and storage
- Mash cooling and starch conversion
- Fungal amylase production
- Fermentation
- Alcohol recovery and dehydration
- Alcohol product and dry grains byproduct storage and shipping
- Stillage drying
- Steam generation and other balance-of-plant support systems.

Fabricated (e.g., tanks, distillation towers, heat exchangers), and manufactured (e.g., pumps, compressors, blowers, centrifuges) equipment included in these areas is similar to that used in petroleum, chemical, pharmaceutical, and food industry applications. Based on discussions with technology suppliers[1,2], it was determined that in an emergency, manufacturing capacity of solid fuel-fired boilers (for steam generation) and centrifuge decanters (for stillage concentration and processing) could create bottlenecks in deployment of ethanol plants.

3. ASSESSMENT OF POTENTIAL CONSTRAINTS

A study by the Department of Energy claims that 66 million acres of pasture land and light forest could be brought into production with corn yielding a potential of 17 billion GPY of ethanol.[4] Based on an average plant size of 50 MMGPY,

this will require construction of 340 plants over the five year period during an imported oil cut-off emergency.

A 50 MMGPY ethanol plant can be constructed in 24 months based on the schedule shown in Figure F-1. It is assumed that coal or wood would be the fuel for steam generation, only particulate control system would be necessary, and flue gas desulfurization systems would not be required. A 50 MMGPY plant uses a 250-300 million Btu/hr boiler. Based on a historical maximum delivery of 55 solid fuel-fired boilers per year in this capacity range (see Appendix B), over a five year period about 220 ethanol plants can become fully operational. Thus at the end of the fifth year, these 220 plants can displace about 472,000 boe/d of oil (= 220 plants x 50 MMGPY Ethanol x 75,670/(115,000 x 365 x 42)) based on boiler manufacturing capacity constraints.

A 50 MMGPY plant requires 3-5 centrifuge decanters, each having 250-400 gallons per minute capacity.[2,3,5] Data on U.S. manufacturing capacity for centrifuges is proprietory to individual equipment suppliers and is not readily available.[6] A leading supplier indicated to Gibbs & Hill that in an emergency, the industry could obtain about five hundred 304 stainless steel castings for centrifuge bowls. Thus, it is concluded that over a five year period, about one hundred 50 MMGPY ethanol plants can become fully commercial displacing about 215, boe/d of oil based on availability of centrifuge decanters.

Figure F-2 shows the deployment rate for corn to ethanol technology based on implementing 100 plants, each of 50 MMGPY capacity. With an average yield of 2.6 gallons of ethanol per bushel of corn, this corresponds to an annual corn resource utilization of about 1.9 billion bushels, representing about 32 percent of U.S. annual corn production. The issues of corn resource constraint and impacts on animal feed markets are controversial (see for example, the Phase I report) and are excluded for the purposes of the present analysis. These issues will be further discussed by OTA in its final analysis.

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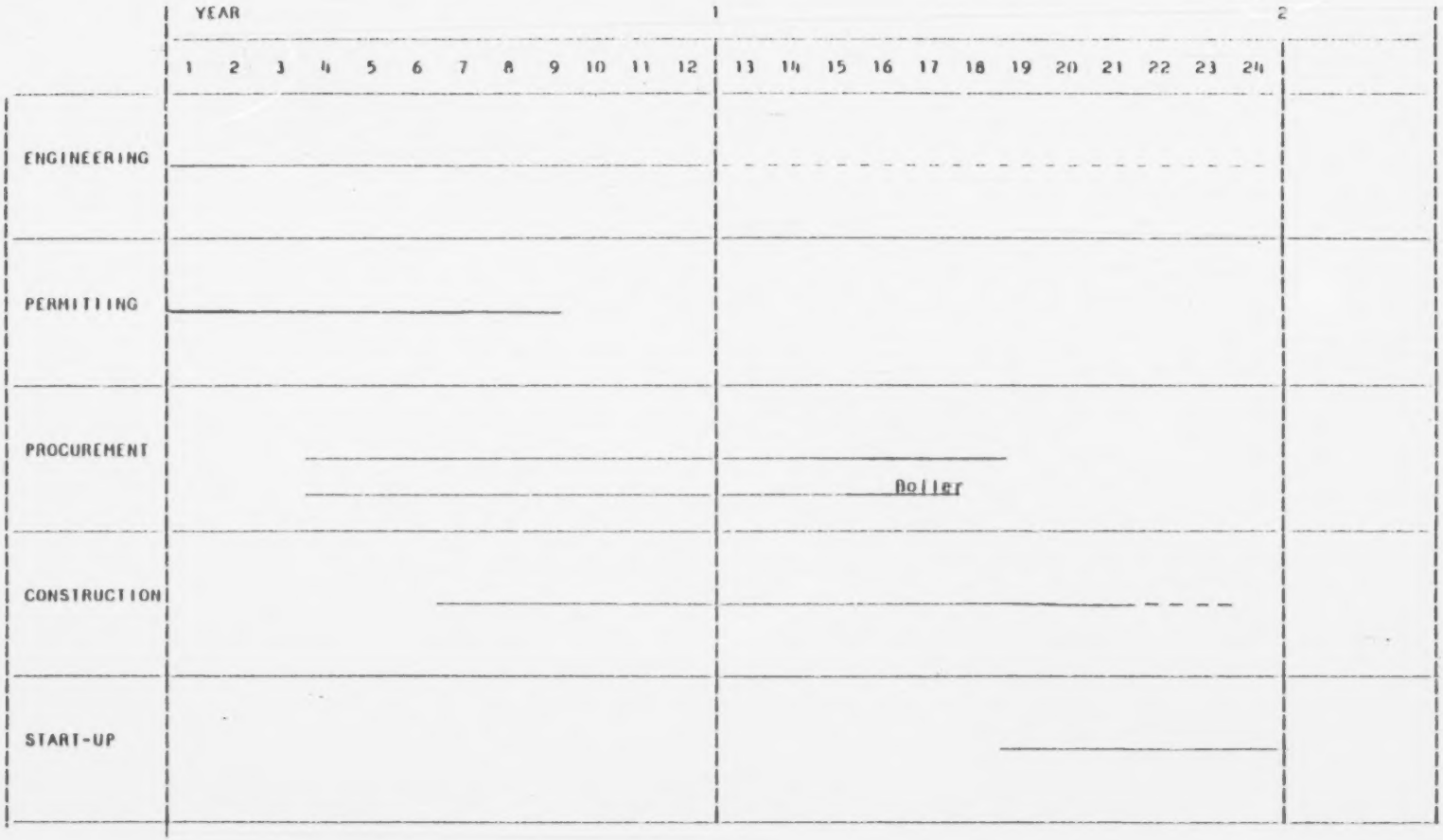

FIGURE F-1

SCHEDULE FOR ENGINEERING AND CONSTRUCTION
50 MMGPY ETHANOL PLANT

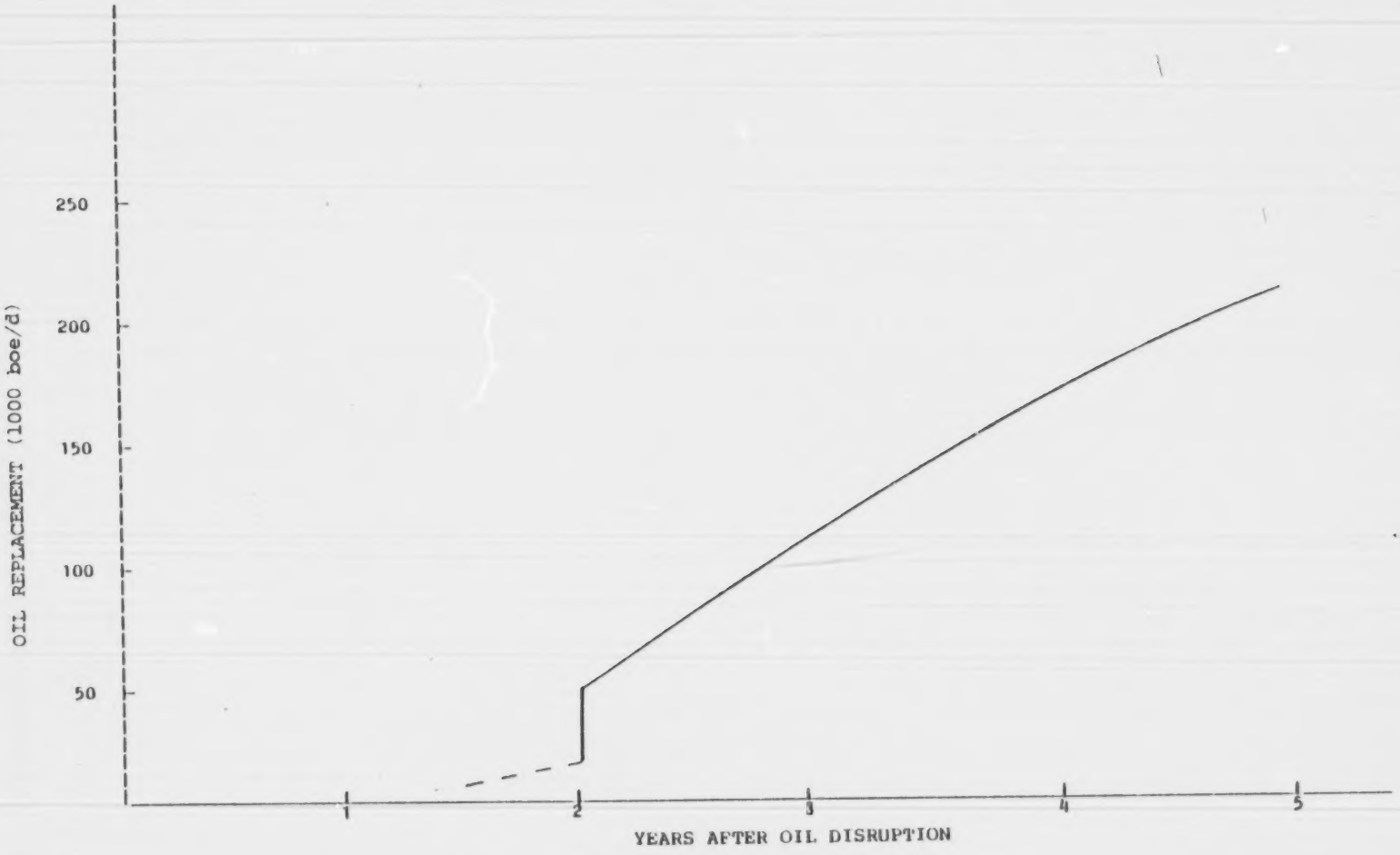

FIGURE F-2

OIL DISPLACEMENT CURVE - CORN TO ETHANOL TECHNOLOGY

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